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Bachelor in Energy Engineering

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Bachelor Thesis

“Distributed Photovoltaic Generation in Spain: Analysis of the Impact of Energy Regulation in the Economic Viability of Photovoltaic Installations for Self Consumption; UC3M Campus of Leganés Case Study”

María de Miguel Garrido

Tutor

David Santos Martín

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ABSTRACT

Keywords: Distributed PV; Self-consumption; Energy Regulation; Spain; NPV; IRR; LCOE.

The aim of this paper is to evaluate the impact that energy regulation has on the viability of distributed PV applications for self-consumption. More precisely, the impact of the application of backup charges on self-consumption as well as the remunerating mechanisms for surplus of electricity injected into the grid.

The current Spanish energy regulation is reviewed, together with those from the international panorama, applicable in some of the countries where distributed solar PV for self-consumption is more relevant. This is done in order to explore the impact of alternative regulatory mechanisms.

The analysis is based on a hypothetical solar installation to be deployed at Carlos III University's Campus of Leganés. A solar potential analysis of the premises was carried out making use of PVSol Software. Furthermore, a tool was developed through Matlab for the techno-economic analysis of the investment.

The main conclusions obtained from this analysis is that the application of variable backup charges for self-consumption has a very negative impact on the profitability of these projects, where the main purpose of the generated electricity is to be consumed locally. In fact, removing the variable backup-charge on self-consumption increases savings by around 24%. Under the current Spanish regulation, the project would not be economically viable, having a negative NPV and very low returns (3%). The implementation of an investment compensation mechanism improves the profitability of the project, having a positive NPV, but offering low returns (5.28%). The most profitable remuneration mechanism is found to be a feed-in-tariff, followed by a net metering mechanism. However, this does not produce a comparable increase in savings given the small percentage of electricity exported to the grid.

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ACRONYMS

AC	Alternating Current
CAPEX	Capital Expenditures
CNMC	Comisión Nacional de los Mercados y la Competencia
DC	Direct Current
DDG	Distributed Dispatchable Generators
DR	Demand Response
EC	European Commission
ECB	European Central Bank
EEG	Erneuerbare Energien Gesetz
EPRI	Electric Power Research Institute
EU	European Union
FEMP	Federal Energy Management Program
FiT	Feed-in-Tariff
GHI	Global Horizontal Irradiation
IRR	Internal Rate of Return
KFW	Kreditanstalt für Wiederaufbau
LCOE	Levelized Cost of Energy
NB	Net Billing
NM	Net Metering
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
OMIE	Operador del Mercado Ibérico de Energía – Polo Español
OMIP	Operador del Mercado Ibérico de Energía – Polo Portugués
O&M	Operation and Maintenance
PPA	Power Purchase Agreement
PV	Photovoltaic
RD	Royal Decree
RES	Renewable Energy Sources
SRECS	Solar Renewable Energy Certificates
ToU	Time of Use Tariff
UC3M	Universidad Carlos III de Madrid
VAT	Value Added Tax
WACC	Weighted Average Cost of Capital

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1. INTRODUCTION

Several circumstances have been favorable for the rapid development of PV technology. Among them there is: fossil fuel shortage, political instability of the main energy supplying countries, the existence of targets to reduce pollutant emissions in the fight against global warming, the improvement in its performance and the decrease in its costs. In fact, the decreasing cost of PV technology and its increasing efficiency, have enabled it to reach grid parity in many countries. This is the point where electricity generated by the solar panels is economically equivalent to that obtained from the grid.

Furthermore, given the growing electricity demand and the increasing environmental awareness, targets regarding renewable energy penetration levels have come into place. There is the EU 20/20/20, the US grid 2030 and the China's 12th five-plan.

According to the Navigant research report of fourth quarter of 2015, the leading countries regarding renewable penetration are China, USA and Germany, followed by Italy, Spain, Japan and India.

It should also be highlighted that slow changes are taking place in the current electricity network, a mainly centralized system, transitioning towards a more decentralized one, seeking sustainability, security of supply and competitiveness. In this context, solar energy, and more specifically, decentralized PV technology, will be key in the pursue of these objectives. However, the measures implemented through the Spanish regulation on self-consumption, as will be explained in further sections, have set stringent constraints that have had a negative impact on the deployment of this technology at a residential and consumer level.

In [1], the financial viability of self-consumption under Spanish energy regulation was evaluated for residential, commercial and industrial prosumers on the one hand, and the government and the electricity network on the other. It was observed that the main implications of such as restrictive self-consumption regulation in comparison with other alternatives (net metering or net billing) is hindering the diffusion of PV for self-consumption applications, as they are no longer economically feasible. For instance, return on investments was found to be negative or low (below 2.2%) for residential, commercial or industrial self-consumption applications.

Therefore, the aim of this project is to evaluate the economic viability of a PV installation at Carlos III University of Madrid's Campus of Leganés under different regulation schemes. The analysis will initially be carried out under the current regulation followed by more favourable scenarios based on the regulations that are being applied in the international panorama as well as past regulations in Spain.

The objectives of doing so are both to prove the impact energy policies and regulations can have on the viability of solar projects and the development of technology but at the same time, trying to highlight the fact that a change in regulation is highly recommended.

For that purpose, a Matlab script has been created, and is presented in Annex B, through which finantial parameters such as NPV, IRR, LCOE and Payback time are calculated for each modelled scenario.

Moreover, besides evaluating different regulatory scenarios, presenting results and deriving conclusions for them, another important aim of this project is to create a tool that can perform an economic analysis of an investment in distributed PV technology. Many tools that can meet this purpose already exist and are available in the market, such as PVSol, which is also used in this project or HOMER Pro. However, these tools do not include all three scopes of the analysis that are considered in this project, the economic, technical and regulatory perspective, lacking one of them.

2. LITERATURE REVIEW

In the following sections, a summary of key information and findings obtained from different research papers will be presented, as they constitute the basis of this analysis.

2.1. Overview of Main Barriers Faced by Distributed PV Systems

There are plenty of circumstances that are favourable for this technology as has been previously explained; however, according to [2] , distributed PV often faces certain barriers. These are explained below:

2.1.1. Non-Economic Barriers

They refer to factors that prevent the development of PV technology or cause an unnecessary increase in costs. They can be:

-Institutional and administrative barriers, such as slow and complicated procedures.

-Market barriers, such as pricing structures that disadvantage renewables, market power, asymmetrical information or the failure to internalize the externality of social and environmental impacts.

-Financial barriers. An example would be the absence of adequate funding opportunities.

-Infrastructure barriers, which refers to the capability of the grid to integrate RES.

-Lack of awareness and skilled personnel.

-Regulatory and policy uncertainty barriers, bad policy or the lack of access to sufficient and transparent information.

Although different directives and framework programs for renewable energy penetration exist, no clear and specific regulations have been implemented yet. There is the 2009/28/EC directive promoting the use of energy from RES; 2006/32/EC, regarding energy efficiency; 2009/72/EC, regulating grid connection; 2004/8/EC, promoting cogeneration, energy efficiency and security of supply and 2013/347/EC, for the development and integration of smart grids.

These directives set targets that must be met within a specified deadline by all member states. However, national authorities are given the freedom to modify their laws as they see fit in order to meet these targets, which results in the implementation of very different national regulations. The current lack of clear and specific regulations makes it difficult for the development of microgrids.

-Distributed Generation Integration. It often constitutes a challenge, given the lack of clear policies, standards or regulations in this domain.

2.1.2. Financial and Economic Barriers

They refer to the economic constraints that can be faced by these projects. They are mainly:

-High upfront cost. RES have a high CAPEX, which makes it recommendable to introduce support mechanisms, such as financial incentives, tax benefits or low-interest loans for these sources of energy.

-Grid Connection Costs or Transmission Expansion. These are considered as capital overheads, increasing total project costs.

2.2. Overview of Energy Policies and Regulations for Distributed PV Systems in the International Panorama

In the following sections, the energy policies and regulations applicable in some of the countries where distributed PV technology for self-consumption has greater relevance according to [3] are reviewed. In order to do so, key parameters for their classification have been presented in order to create a common frame.

2.2.1. Parameters for the Classification Self-Consumption Schemes

The following parameters will be employed for a clear definition of the regulatory mechanisms regarding self-consumption of energy. This classification has been previously used in [3].

1. Right to Self-Consume

It refers to whether self-consumption is legally permitted in the country, that is whether microgrid owners have the legal right to connect their system to the grid and consume part of their generated electricity.

2. Revenues from Self-Consumed Electricity

These can occur as savings on the electricity bill or as additional revenues, such as self-consumption bonus or green certificates.

3. Charges for Distribution and / or Transmission Networks.

It refers to whether prosumers have to pay part of the costs of the electricity network they are connected to.

4. Revenues from Surplus Electricity Sold to the Grid

Different compensation mechanisms apply for the surplus electricity sold to the grid:

-Net Metering. Both consumed electricity and surplus sold to the grid are valued at the retail price.

-Net Billing. Surplus is valued at a lower price than the cost of electricity bought from the grid, generally wholesale price.

-Pure Self-Consumption. Surplus electricity is not remunerated.

As indicated in [1], it can be derived from it that a Net Metering scheme implies a passive subsidy to PV, given that prosumers will be paid higher prices for their produced electricity than other generators. Whereas Net Billing at wholesale price would create competitive equality among producers, as prosumers would sell their surplus at pool price as so will the rest of generators.

5. Maximum Timeframe Compensation

It refers to the time during which credit compensation for electricity injected is permitted. This is important for net metering schemes, where the surplus electricity is paid at the retail price. Therefore, it is equivalent to having the right to consume the same amount of electricity from the grid as has been generated and injected into it, but at a different point in time. Credits are assigned in exchange for that surplus, and this parameter (maximum timeframe compensation) establishes the amount of time within which those credits can be used.

6. Geographical Compensation

It refers to consumption and generation compensation such as "Virtual Net-Metering", "Meter Aggregation" and "Peer to Peer" that can be applicable to certain areas.

An example of this could be the case of Australia, that counts with a vast territory with low density population, where population is concentrated in urban centers that are far between. It is then in the interest of both the government and the central grid to support the development of microgrids in remote areas as it would have a much lower cost than extending the electricity network to connect them.

7. Regulatory Scheme Duration

Duration of the compensation mechanism in years.

8. Third Party Ownership Accepted

Whether third party ownership of the generation asset is allowed (for example through leases and PPAs).

9. Grid Codes and Additional Taxes or Fees

Additional costs to be borne by PV owners. These can be undifferentiated costs or specific costs (ie. back-up costs). Specific grid codes can apply as well, such as: frequency-based power reduction, reactive power control, voltage dips, inverter reconnection conditions and output power control among others.

10. Other Enablers of Self-Consumption

It refers to additional support mechanisms such as storage, demand side management or electricity rates with ToU.

11. PV System Size Limitations

It establishes which segments are considered under the discussed compensation scheme in terms of their capacity limit.

12. Electricity System Limitations

Maximum penetration of PV technology considered within self-consumption regulation.

13. Additional Features

All elements that have not been previously mentioned.

2.2.2. Spanish Energy Regulation

As explained in [3] and [1], under the Royal Decree 900/2015 (9th October 2015), Spain has neither a net metering, nor a net billing scheme, but two types of self-consumption:

-Type I corresponds to PV systems below 100kW. They are legally considered as consumers and thus they will not receive any monetary compensation for the excess of electricity they deliver to the grid.

-Type II corresponds to those systems that are greater than 100kW. They are legally considered as both consumers and generators, therefore they must be registered and if willing to sell their surplus electricity, they will do so in the spot market at the wholesale price, while paying the grid-access charge of 0.5 €/MWh determined in RD 1544/2011 as well as a generation tax of 7% on electricity produced according to RD 15/2012.

Moreover, according to the RD 900/2015, two backup charges, commonly known as ”Sun tax”, must be paid as well by those PV producers that are connected to the grid: a variable one, depending on self-consumed energy and a fixed one, depending on installed capacity, which will only apply if battery storage is used.

However, certain installations are partially or totally exempt from the second ”solar tax”: installations smaller than 10 kW, all installations in the Canary Islands and the cities of Ceuta and Melilla are totally exempt from it while systems in Mallorca and Minorca will pay a reduced price. Moreover, installations with co-generation will be exempt from this tax until 2020.

Community ownership under Royal Decree 900/2015 was forbidden under all circumstances. However, the 2^{nd} of June 2017, this decree was partially deemed void by Spain's Constitutional Court and community ownership was since allowed.

Furthermore, it is necessary to register the system as an electricity production facility as stated in RD 413 / 2014 and permission from both the corresponding electricity supplier and the Spanish Government must be granted prior to the installation of any grid-connected source. Furthermore, system capacity must not exceed contracted power and at least two meters must be installed, depending on whether it is a low voltage or a high voltage connection.

The penalty for not complying with the aforementioned conditions amounts to a total of 60 million euros. Given the retroactive character of this law, such penalty will be applied as well to all PV technology that was installed before its implementation. It should be noted that the fines are double of what a nuclear plant would face in the event of a radioactive leak.

	Spain below 100 kW	**Spain above 100 kW**
1	Yes	Yes
2	Savings on the electricity bill	Savings on the electricity bill
3	Yes (”sun tax”)	Yes (”sun tax”)
4	None	Wholesale price minus generation tax and access charge
5	Real time	Real time
6	None	None
7	Unlimited	Unlimited
8	None	Yes
9	Above 10 kW- with exceptions	Yes with exceptions
10	None	None
11	Below or equal to contracted capacity	Below or equal to contracted capacity
12	Licence to grant permission from Distributor & Spanish Government	Licence to grant permission from Distributor & Spanish Government
13	Taxes on batteries	Taxes on batteries

TABLE 2.1. SUMMARY OF SELF-CONSUMPTION REGULATION IN SPAIN

2.2.3. Summary of Country Positioning Regarding Self-Consumption Policies

The principle of self-consumption consists on generating electricity and consuming it locally so as to produce savings through the reduction of the electricity bill. It is legally permitted in many countries, however, significant differences in their regulation exist. Summing up the information presented in [3], the following points can be highlighted:

-Variable grid costs on self-consumption to support the grid are not well perceived. In fact, several countries have modified their structure to increase fixed costs and reduce or eliminate the variable component, such as Australian grid operators, or are discussing it, such as French grid operators.

-Regarding the compensation for the surplus electricity injected into the grid, 5 main options can be distinguished:

a) **Pure self-consumption**. The excess electricity is not remunerated at all. It is the case of Spain for systems below 100 kW.

b) Excess paid at **wholesale** price with **bonus** (Germany, China, Italy, Sweden) or **penalty** (Belgium and Spain for systems above 100 kW). Penalty refers to the costs the prosumer has to incur in, so as to be able to trade their generated electricity, while bonus can be considered as the feed-in premium that incentivizes PV injection.

c) Surplus paid at **FiT between wholesale price and retail price**, such is the case of Denmark.

d) **Full net metering**. Surplus PV electricity is paid at the retail price. This scheme is applied in Belgium (in Flanders and Wallonia), Brazil, some jurisdictions in Canada, Israel, Mexico, the Netherlands and several states in the USA.

e) **Surplus paid above retail price**. It is applied in the UK.

-Special cases of self-consumption and net-metering are applied in certain countries:

Virtual net-metering between distant sites, under specific conditions, exists in Mexico and Brazil. Another example is Multi-Family housing, where net production in one site is shared among several prosumers. This is the case of the Netherlands.

-Remuneration schemes can have a limit in time (10, 20 years) such is the case of the FiTs in China, Denmark, France and Germany.

-Third party ownership is legal in most countries. This implies the owner of the PV system does not does necessarily have to be the same as the consumer of electricity.

-Compliance with grid codes is often required as well in order to guarantee the correct functioning of the PV system as well as the grid, from a technical perspective.

3. PROCEDURE EXPLANATION

Five scenarios have been modelled to represent possible energy regulations under which the investment could take place. For each of them, different compensation mechanisms for the surplus of electricity injected into the grid have been considered, as well as the application of taxes and backup charges to support the grid.

For each modelled scenario the NPV, IRR, LCOE and payback time will be calculated. The analysis of this investment will be performed considering a 20 years time period, as this is the assumed lifetime of the system, based on [4]. Although there are other papers such as [5] that consider the lifetime of PV systems to be 25 years, 20 years has been selected as a more conservative approach and to offset the fact that no replacement costs have been considered (although they have partially been considered indirectly through O&M costs).

3.1. Site and Resource Assessment

This is the technical campus of Carlos III's University in Madrid, in the municipality of Leganés. It is located at a latitude of 40º 20′ [1]and a longitude of 3º 45′.

Fig. 3.1. UC3M Campus of Leganes Aerial View (Google Earth Pro)

This location presents appropriate conditions for the installation of Solar En-

[1]This parameter is relevant to determine the optimum tilt of the panels.

ergy, being Madrid one of the regions in Spain with greater solar insolation, having an average annual GHI in the range of 1700 kWh/m^2.

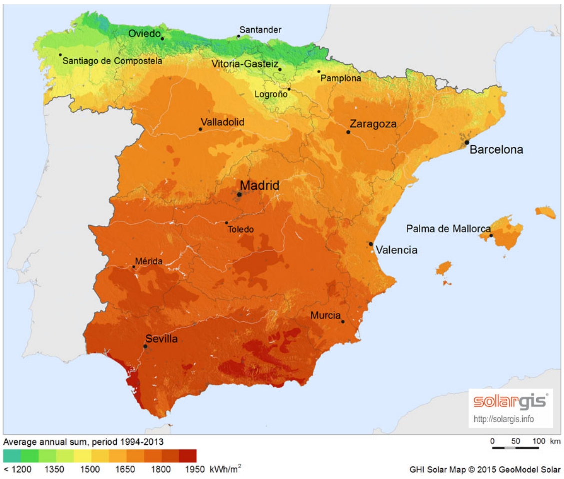


Fig. 3.2. Average Annual GHI in Spain (SolarGis)

In the specific case of our analysis, the municipality of Leganés, the data for the GHI was obtained from PVSol software and plotted through Matlab. The results are presented below.

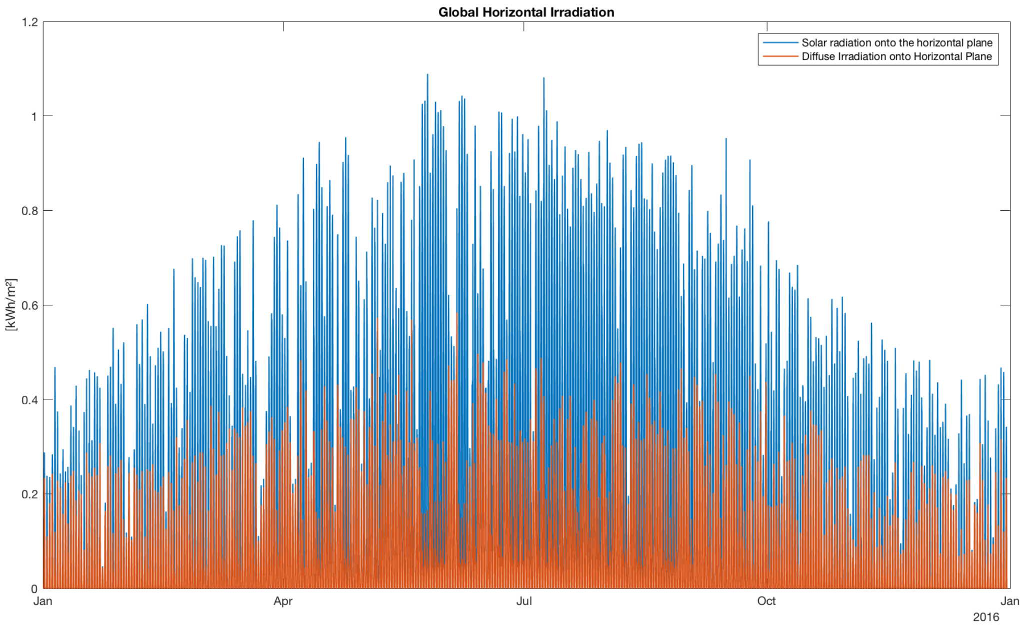


Fig. 3.3. Global Horizontal Irradiation in Leganés

3.2. Load

Consumption data for this campus was obtained from [6], where it is publicly available.

3.2.1. Considerations for Load

According to the European directive 2000/84/CE, incorporated in the Royal Decree of 2002, two changes of time per year must take place in the countries of the European Union as an energy efficiency measure. Therefore:

-The 27th of March 2016, the clock was changed: at 2 am it became 3 am. Consequently, the data for that day presents 1 hour less. In order to have a valid format, the values for 2 am have been copied for 3 am as well.

-The 30th of October 2016 at 3 am the clock was changed back to 2 am. Consequently, there would be 1 hour more for this day, which was solved by removing the data corresponding to 2 am.

-Furthermore, 2016 happened to be a leap year, having 366 days. In order for this data to match the length of other elements in the analysis, with 365 days, the data corresponding to the 29th of February was removed.

-Finally, the available data was provided in quarterly values, therefore it had to be properly adjusted into hourly values. The approach taken was to calculate the mean values within each hour.

-As has been previously mentioned, under Order ETU/315/2017 of the "BOE", an 0.8% increase in load was expected in Spain. This percentage has been included in order to model a possible evolution of the load throughout the investment period.

The final result of the load can be seen in figure 3.4.

3.3. Grid Purchases and Exports

Grid purchases will be defined as the difference between the load and PV generation. It should be noted that no losses are included in this equation given that the PV Generation considered in the analysis already accounts for transmission

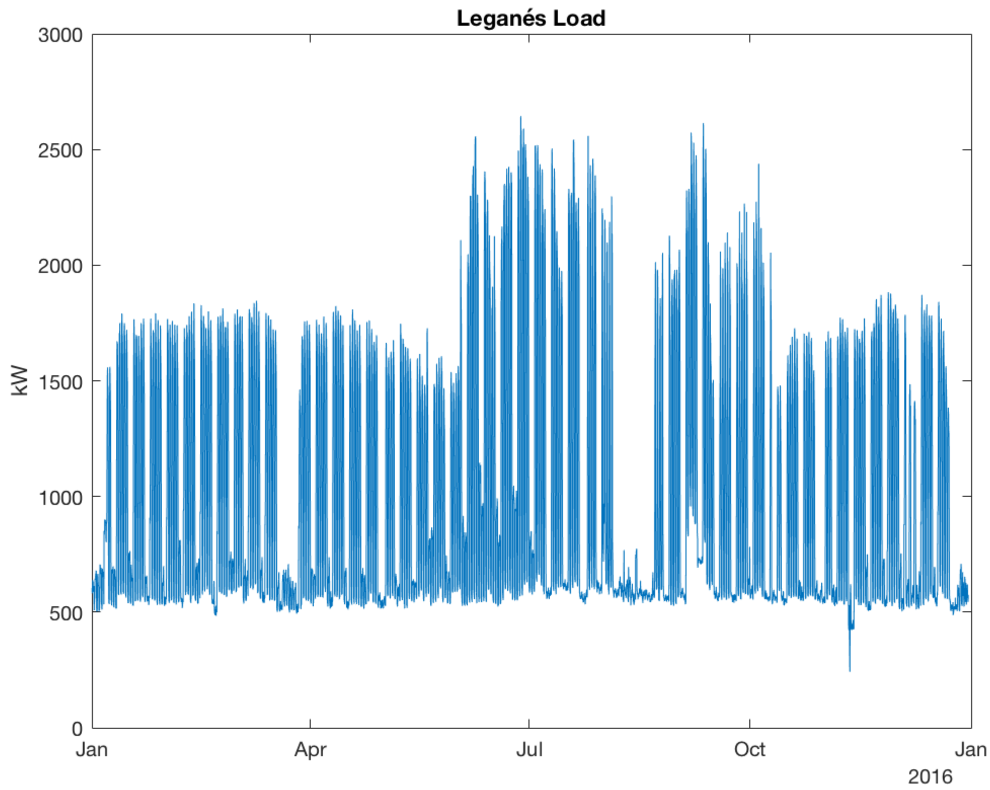


Fig. 3.4. UC3M Leganés Load

losses.

However, simply considering the difference between them does not account for those periods where PV generation is greater than the load, and therefore, electricity would be exported to the grid. This is solved by considering that negative values of grid purchases will be assigned with a negative sign (to make them positive) to grid exports.

Finally, bringing together each of the components, the overall operation of the system is shown in figure 3.5.

Another important aspect of the PV installation is renewable fraction, which is the percentage of load that is covered through renewable resources, in this case, solar generation. In this particular installation, this parameter would amount to an average of 11,91%, considered over the 20 years of project lifetime.

It should be noted that this percentage refers exclusively to the solar generation produced by the installation, without considering the renewable penetration of the grid, which would result in a greater overall renewable fraction.

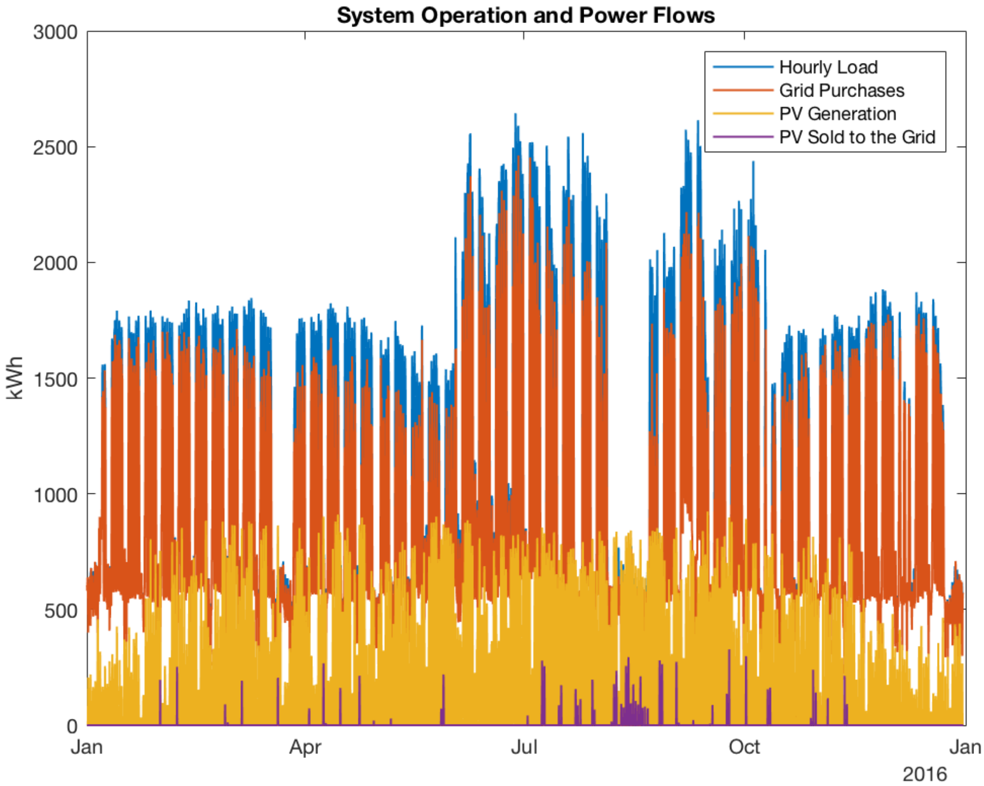


Fig. 3.5. System Operation and Power Flows

3.4. Electricity Prices

The campus of Leganés has a Tariff 6.1.A . The information on the winning bid, together with the parameters for the determination of the offered price are available at [6].

This type of tariff is a ToU tariff applied for high voltage users and counts with 6 different prices. The vector for the variable price of electricity, is calculated as follows:

$$P = 0.5 * (OMIE * Ms + As) + 0.5 * (OMIP * Mf + Af) \tag{3.1}$$

Where OMIE and OMIP are the wholesale electricity prices for both the Spanish and Portuguese branches and Ms, As, Mf and Af are defined coefficients.

To these electricity prices, energy network access fees must also be applied. They have been obtained from [7]. Furthermore, a vector defining when each of these 6 prices is to be applied must also be defined. The resulting tariff is presented in figure 3.6.

A fixed term must also be considered, which is the term for contracted power.

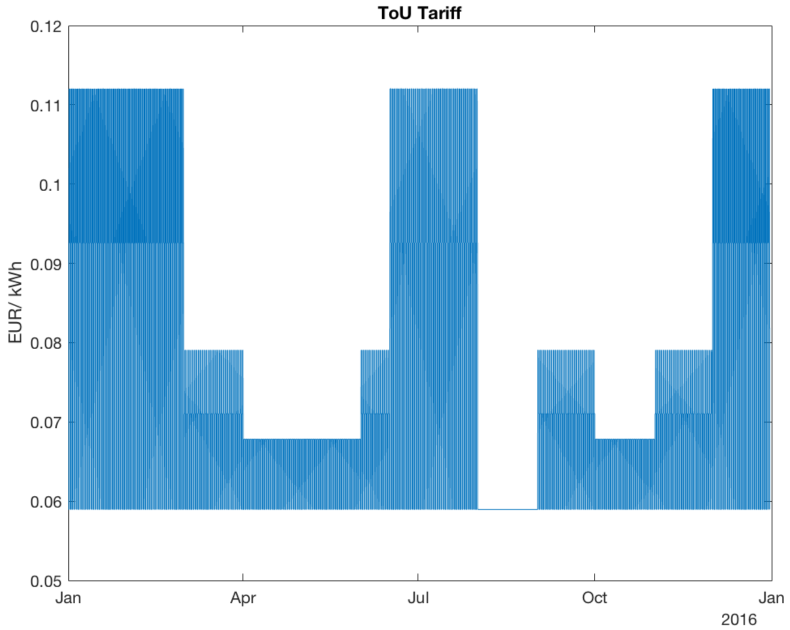


Fig. 3.6. ToU Tariff

This is the power the utility commits to be able to provide at all times, if required. The prices for contracted power as well as the University's contracted capacity can be obtained from their electricity bills (provided internally). [2]. Finally, a 2% escalation rate is considered for electricity prices, according to the ECB inflation rate.

Regarding how should the VAT be considered in the analysis, the following must be clarified:

First of all, VAT is a tax that is applicable in certain countries to all companies that sell products or services (except those companies that are VAT-exempt due to their activity) and is added on top of their selling price, amounting to 4, 10 or 21% (in Spain) of their price depending on the type of product; this is known as output VAT. However, at the same time, each company must pay VAT for the acquisition of products and/ or services related to their operation, which is known as input VAT.

In this project, it has been assumed that output VAT related to the export of electricity to the grid is compensated with input VAT corresponding to the purchase of resources required to operate the PV plant, including the initial investment, otherwise, it would be balanced through the Treasury. Therefore, VAT to be

[2]This parameter is very relevant to our analysis, given that under the current spanish energy regulation the capacity of the PV installation must not exceed contracted capacity.

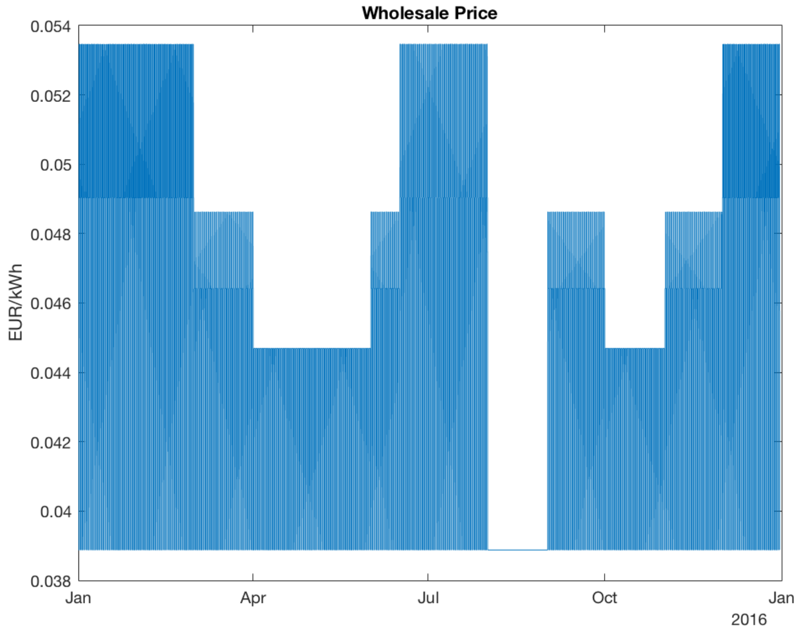


Fig. 3.7. Wholesale Price of Electricity

paid against and to be collected related to the operation of the PV generation plant would be equal and would have no net impact on cash flows, as suggested in [8]. However, input VAT for the electricity bought from the grid must be considered as it cannot be compensated. Therefore, VAT has been included for electricity bought from the grid but not for export tariffs.

3.5. Export Tariffs

In this section the compensation mechanisms for the surplus of electricity injected into the grid employed in this analysis are presented.

3.5.1. Wholesale Price

This remuneration mechanism would fall under a ”Net Billing” mechanism. The values indicated in [6] as well as time vector employed for the retail price in order to model the ToU tariff have been used. The result is shown below in figure 3.7.

3.5.2. Feed-in-Tariff

A FiT of 0.15675 €/kWh has been used as per Royal Decree RD 14/2010. A 2% annual increase has also been considered, as indicated in [5].

3.5.3. Retail Price

This remuneration mechanism is applied under a ”Net Metering” mechanism.

4. DETAILED SOLAR POTENTIAL ANALYSIS

4.1. Solar Potential Analysis

The specific solar potential for the UC3M Campus of Leganes was evaluated through PVSol software, where a 3D design of the premises was created in order to evaluate the maximum capacity of a solar installation. This was done taking into account the constraints of space and shading, as well as those posed by regulation, as installed capacity must not exceed contracted capacity, which amounts to 1900 kW.

In this analysis, both maintenance paths and the setback for all rooftop areas have been considered. The latter is the minimum distance that must be left between the PV panels and the border of the roof, which depends on the type of installation. The standard setback for roof-mounted systems has been used, which according to PVSol amounts to 1.2 m for each edge.

4.1.1. Considerations for Solar Potential Analysis

To begin with, the simulations of the whole premises had to be carried out in two separate files, given the extension of the campus, which led to slow performance and computational problems within the software.

Secondly, the optimum tilt and orientation of the panels had to be determined. This step is of great importance, given that the selected system is fixed (without tracking system).

- Regarding the optimum tilt, given that Madrid is located in the northern hemisphere, south orientation (180 °) was selected.

- On the other hand, the tilt is strongly dependent on the latitude. According to NREL, for regions located within latitudes 25° and 50°, the optimum tilt should be calculated as follows:

$$\text{Optimum. tilt} = \text{latitude} * 0.76 + 3.1 \tag{4.1}$$

resulting in 33.75°.

On the third place, there are currently installed panels on campus. These were installed before 2001 and will therefore not be considered in the analysis, as it is assumed that they are close to the end of their lifetime and they are likely to have considerably lower efficiency than the proposed panels, as remarkable progress has been made in the field in the last decade.

PVSol offers the possibility to carry out a shading analysis throughout the year, so as to be able to determine which panels would be heavily shaded and would therefore cause a considerable reduction in the overall performance of the system. Once this analysis has been carried out, panels with a high degree of shading have been manually removed.

Resulting from the simulations, a capacity of 940 kWp has been obtained. A detailed explanation of the technical specifications of the installation will be presented in the next section. The datasheets of the components can be found in Annex A.

Once solar assessment has been completed, the expected energy to be produced by the solar panels was obtained from PVSol. This is the DC energy at the inverter input and takes into account the efficiency of the modules as well as the losses from temperature effects and shading, among others.

However, further losses must be applied as stated in PVSol:
- A decrease in 0.53% due to input voltage deviations from rated voltage.
- 4.23% due to the DC/AC conversion at the inverters.
- 0.07%, which corresponds to stand-by consumption.
- 1% decrease is considered for cable losses.

Resulting in a further decrease of 5.83% to obtain the output power of the system. The total PV generation for the first year is shown in figure 4.1.

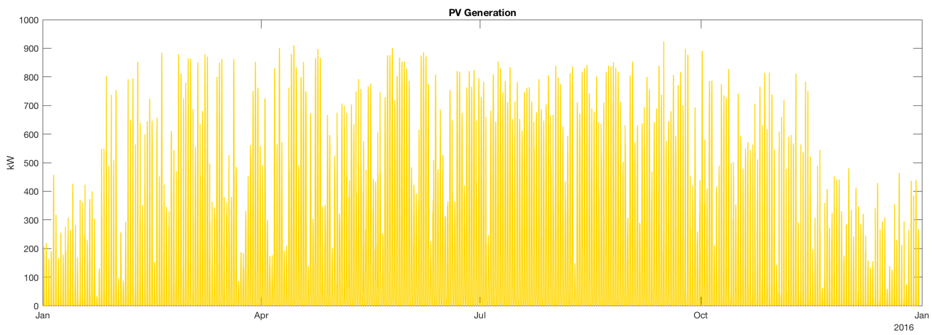


Fig. 4.1. PV Generation

Furthermore, according to [9], which was a study carried out by NREL, 2000 different projects with their related degradation rates were evaluated, obtaining a median of 0.5% degradation rate per year. However, there are many others, such as [9] and [5] that suggest the average is around 0.8% and therefore, this figure should be used instead. The latter has been selected and incorporated to our analysis so as to model the loss of efficiency of the PV panels and consequently, their loss in production.

4.2. Summary of System 1

Aerial View of Campus - PV System I and Panel Layout

3D, Grid-connected PV System		
Climate Data	Madrid, ESP (-)	
PV Generator Output	518.76	kWp
PV Generator Surface	2,349.9	m²
Number of PV Modules	1441	
Number of Inverters	17	

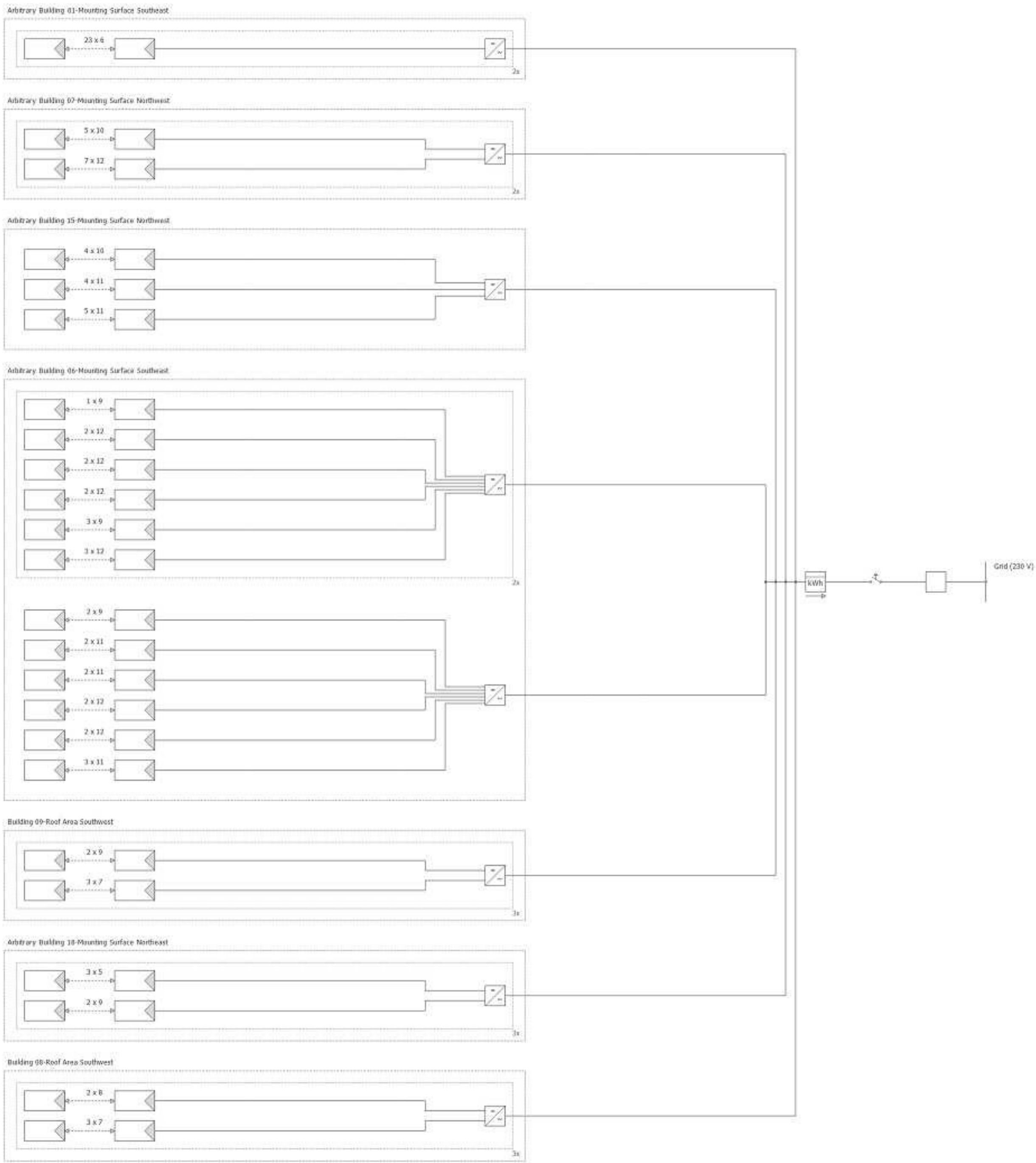
The yield		
PV Generator Energy (AC grid)	684,591	kWh
Spec. Annual Yield	1,319.67	kWh/kWp
Performance Ratio (PR)	76.6	%
Calculation of Shading Losses	14.5	%/year
CO_2 Emissions avoided	410,754	kg / year
Total investment costs	778,140.00	$

Inverter	
1. Module Area	**Arbitrary Building 01-Mounting Surface Southeast**
Inverter 1*	2 x FRONIUS CL 48,0
Manufacturer	Fronius International
Configuration	MPP 1: 23 x 6
2. Module Area	**Arbitrary Building 07-Mounting Surface Northwest**
Inverter 1*	2 x TRIO-TM-50.0
Manufacturer	ABB
Configuration	MPP 1+2: 7 x 12 MPP 3: 5 x 10
3. Module Area	**Arbitrary Building 15-Mounting Surface Northwest**
Inverter 1*	1 x TRIO-TM-50.0
Manufacturer	ABB
Configuration	MPP 1: 5 x 11 MPP 2: 4 x 11 MPP 3: 4 x 10
4. Module Area	**Arbitrary Building 06-Mounting Surface Southeast**
Inverter 1*	2 x Sunny Tripower CORE1
Manufacturer	SMA Solar Technology AG
Configuration	MPP 1: 3 x 12 MPP 2: 3 x 9 MPP 3: 2 x 12 MPP 4: 2 x 12 MPP 5: 2 x 12 MPP 6: 1 x 9
Inverter 2*	1 x Sunny Tripower CORE1
Manufacturer	SMA Solar Technology AG
Configuration	MPP 1: 3 x 11 MPP 2: 2 x 12 MPP 3:

5. Module Area	**Building 09-Roof Area Southwest**
Inverter 1*	3 x Sunny Tripower 15000TL-30
Manufacturer	SMA Solar Technology AG
Configuration	MPP 1:
	3 x 7
	MPP 2:
	2 x 9
6. Module Area	**Arbitrary Building 18-Mounting Surface Northeast**
Inverter 1*	3 x PVI-12.5-TL-OUTD
Manufacturer	ABB
Configuration	MPP 1:
	2 x 9
	MPP 2:
	3 x 5
7. Module Area	**Building 08-Roof Area Southwest**
Inverter 1*	3 x PVI-12.5-TL-OUTD
Manufacturer	ABB
Configuration	MPP 1:
	3 x 7
	MPP 2:
	2 x 8

AC Mains		
Number of Phases	3	
Mains Voltage (1-phase)	220	V
Displacement Power Factor (cos phi)	+/- 1	

* The guarantee provisions of the respective manufacturer apply



Detailed Inverter Configuration

Results per Module Area

Arbitrary Building 01-Mounting Surface Southeast		
PV Generator Output	99.36	kWp
PV Generator Surface	450.1	m²
Global Radiation at the Module	1735.6	kWh/m²
PV Generator Energy (AC grid)	131726.8	kWh/year
Spec. Annual Yield	1325.8	kWh/kWp
Performance Ratio (PR)	76.4	%
Arbitrary Building 07-Mounting Surface Northwest		
PV Generator Output	96.48	kWp
PV Generator Surface	437.0	m²
Global Radiation at the Module	1735.6	kWh/m²
PV Generator Energy (AC grid)	126306.5	kWh/year
Spec. Annual Yield	1309.1	kWh/kWp
Performance Ratio (PR)	75.4	%
Arbitrary Building 15-Mounting Surface Northwest		
PV Generator Output	50.04	kWp
PV Generator Surface	226.7	m²
Global Radiation at the Module	1722.8	kWh/m²
PV Generator Energy (AC grid)	64013.4	kWh/year
Spec. Annual Yield	1279.2	kWh/kWp
Performance Ratio (PR)	74.3	%
Arbitrary Building 06-Mounting Surface Southeast		
PV Generator Output	155.16	kWp
PV Generator Surface	702.8	m²
Global Radiation at the Module	1709.9	kWh/m²
PV Generator Energy (AC grid)	203323.1	kWh/year
Spec. Annual Yield	1310.4	kWh/kWp
Performance Ratio (PR)	76.6	%
Building 09-Roof Area Southwest		
PV Generator Output	42.12	kWp
PV Generator Surface	190.8	m²
Global Radiation at the Module	1718.5	kWh/m²
PV Generator Energy (AC grid)	56897.3	kWh/year
Spec. Annual Yield	1350.8	kWh/kWp
Performance Ratio (PR)	78.6	%
Arbitrary Building 18-Mounting Surface Northeast		
PV Generator Output	35.64	kWp
PV Generator Surface	161.4	m²
Global Radiation at the Module	1718.5	kWh/m²
PV Generator Energy (AC grid)	48209.8	kWh/year
Spec. Annual Yield	1352.7	kWh/kWp
Performance Ratio (PR)	78.7	%

4.3. Summary of System 2

Aerial View of Campus - PV System II and Panel Layout

3D, Grid-connected PV System		
Climate Data	Madrid, ESP (-)	
PV Generator Output	421.2	kWp
PV Generator Surface	1,907.9	m²
Number of PV Modules	1170	
Number of Inverters	16	

The yield		
PV Generator Energy (AC grid)	559,921	kWh
Spec. Annual Yield	1,329.35	kWh/kWp
Performance Ratio (PR)	77.1	%
Calculation of Shading Losses	13.8	%/year
CO_2 Emissions avoided	335,953	kg / year
Total investment costs	631,800.00	$

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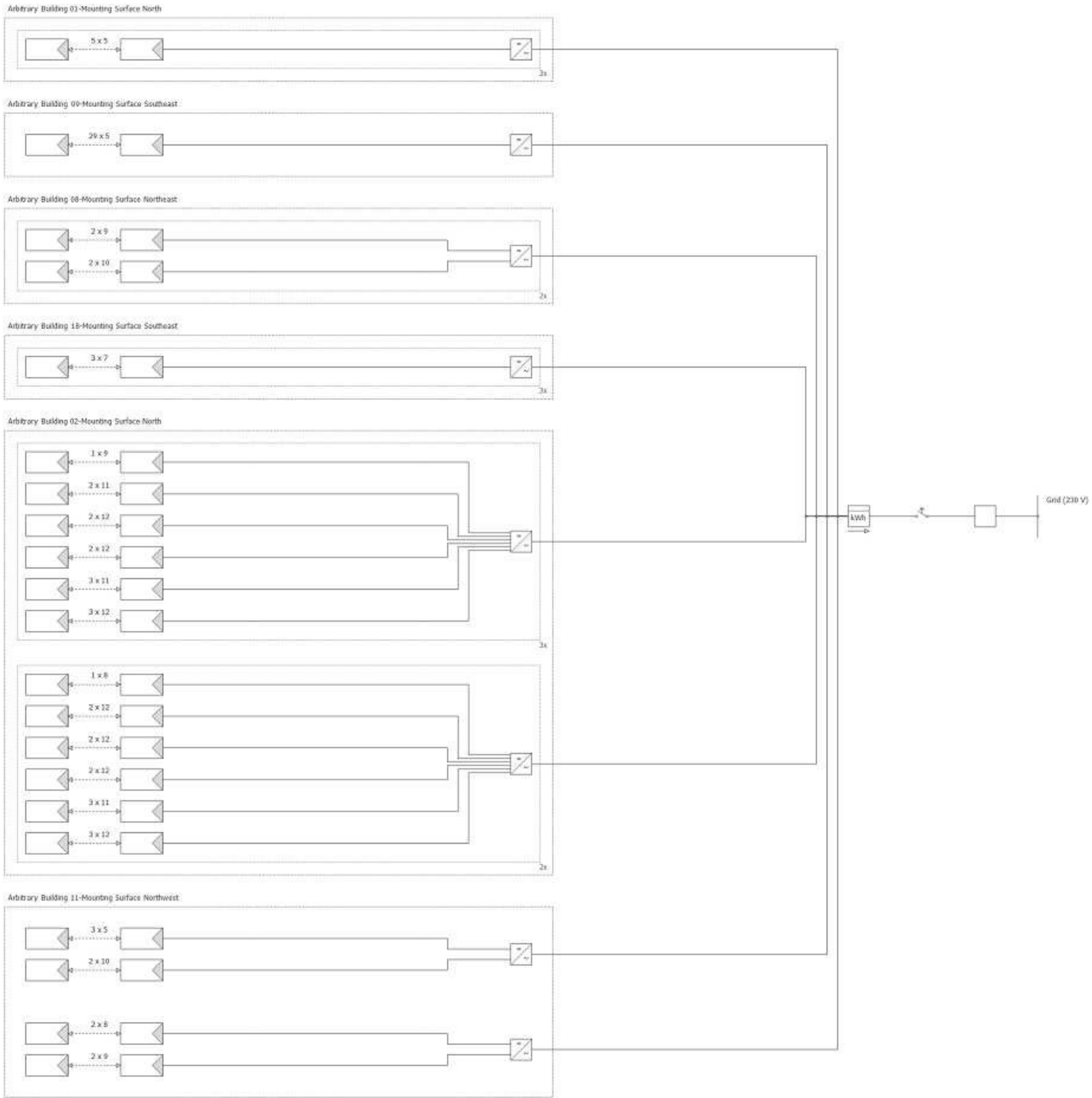
Inverter	
1. Module Area	**Arbitrary Building 01-Mounting Surface North**
Inverter 1*	3 x FRONIUS IG Plus 100 V-3
Manufacturer	Fronius International
Configuration	MPP 1: 5 x 5
2. Module Area	**Arbitrary Building 09-Mounting Surface Southeast**
Inverter 1*	1 x FRONIUS CL 48,0
Manufacturer	Fronius International
Configuration	MPP 1: 29 x 5
3. Module Area	**Arbitrary Building 08-Mounting Surface Northeast**
Inverter 1*	2 x PVI-12.5-TL-OUTD
Manufacturer	ABB
Configuration	MPP 1: 2 x 10 MPP 2: 2 x 9
4. Module Area	**Arbitrary Building 18-Mounting Surface Southeast**
Inverter 1*	3 x FRONIUS IG Plus 100 V-3
Manufacturer	Fronius International
Configuration	MPP 1: 3 x 7

5. Module Area	**Arbitrary Building 02-Mounting Surface North**
Inverter 1*	3 x Sunny Tripower CORE1
Manufacturer	SMA Solar Technology AG
Configuration	MPP 1:
	3 x 12
	MPP 2:
	3 x 11
	MPP 3:
	2 x 12
	MPP 4:
	2 x 12
	MPP 5:
	2 x 11
	MPP 6:
	1 x 9
Inverter 2*	2 x Sunny Tripower CORE1
Manufacturer	SMA Solar Technology AG
Configuration	MPP 1:
	3 x 12
	MPP 2:
	3 x 11
	MPP 3:
	2 x 12
	MPP 4:
	2 x 12
	MPP 5:
	2 x 12
	MPP 6:
	1 x 8

6. Module Area	**Arbitrary Building 11-Mounting Surface Northwest**
Inverter 1*	1 x PVI-12.5-TL-OUTD
Manufacturer	ABB
Configuration	MPP 1:
	2 x 10
	MPP 2:
	3 x 5
Inverter 2*	1 x PVI-12.5-TL-OUTD
Manufacturer	ABB
Configuration	MPP 1:
	2 x 9
	MPP 2:
	2 x 8

AC Mains		
Number of Phases	3	
Mains Voltage (1-phase)	220	V
Displacement Power Factor (cos phi)	+/- 1	

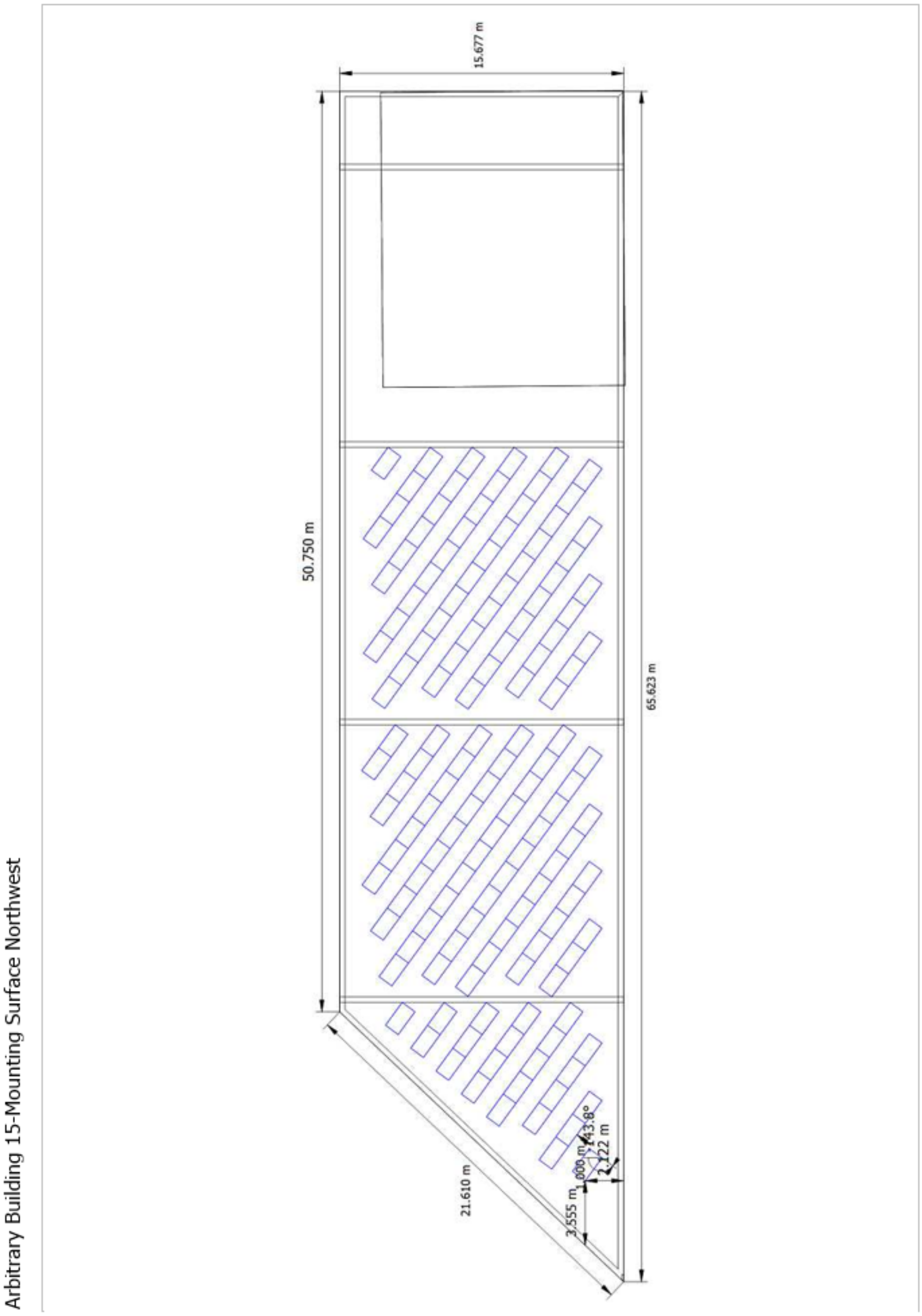


Detailed Inverter Configuration

Results per Module Area		
Arbitrary Building 01-Mounting Surface North		
PV Generator Output	27	kWp
PV Generator Surface	122.3	m²
Global Radiation at the Module	1714.2	kWh/m²
PV Generator Energy (AC grid)	35499.3	kWh/year
Spec. Annual Yield	1314.8	kWh/kWp
Performance Ratio (PR)	76.7	%
Arbitrary Building 09-Mounting Surface Southeast		
PV Generator Output	52.2	kWp
PV Generator Surface	236.5	m²
Global Radiation at the Module	1731.3	kWh/m²
PV Generator Energy (AC grid)	66272.5	kWh/year
Spec. Annual Yield	1269.6	kWh/kWp
Performance Ratio (PR)	73.3	%
Arbitrary Building 08-Mounting Surface Northeast		
PV Generator Output	27.36	kWp
PV Generator Surface	123.9	m²
Global Radiation at the Module	1701.4	kWh/m²
PV Generator Energy (AC grid)	33559.7	kWh/year
Spec. Annual Yield	1226.6	kWh/kWp
Performance Ratio (PR)	72.1	%
Arbitrary Building 18-Mounting Surface Southeast		
PV Generator Output	22.68	kWp
PV Generator Surface	102.7	m²
Global Radiation at the Module	1705.7	kWh/m²
PV Generator Energy (AC grid)	29707.9	kWh/year
Spec. Annual Yield	1309.9	kWh/kWp
Performance Ratio (PR)	76.8	%
Arbitrary Building 02-Mounting Surface North		
PV Generator Output	267.12	kWp
PV Generator Surface	1,210.0	m²
Global Radiation at the Module	1727.1	kWh/m²
PV Generator Energy (AC grid)	360088	kWh/year
Spec. Annual Yield	1348	kWh/kWp
Performance Ratio (PR)	78.1	%
Arbitrary Building 11-Mounting Surface Northwest		
PV Generator Output	24.84	kWp
PV Generator Surface	112.5	m²
Global Radiation at the Module	1731.3	kWh/m²
PV Generator Energy (AC grid)	34798.7	kWh/year
Spec. Annual Yield	1400.9	kWh/kWp
Performance Ratio (PR)	80.9	%

4.4. Panel Layout

4.4.1. System I



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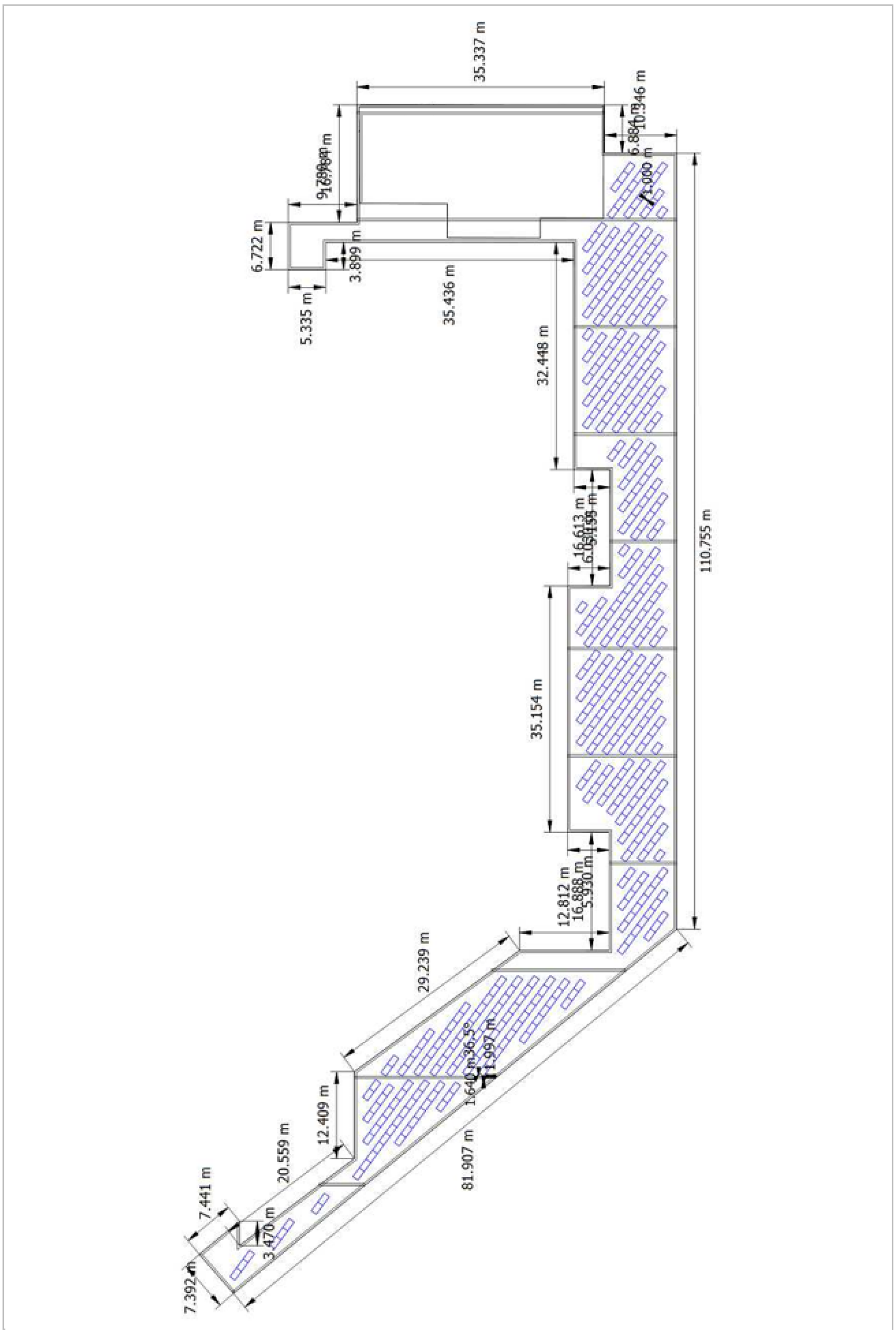
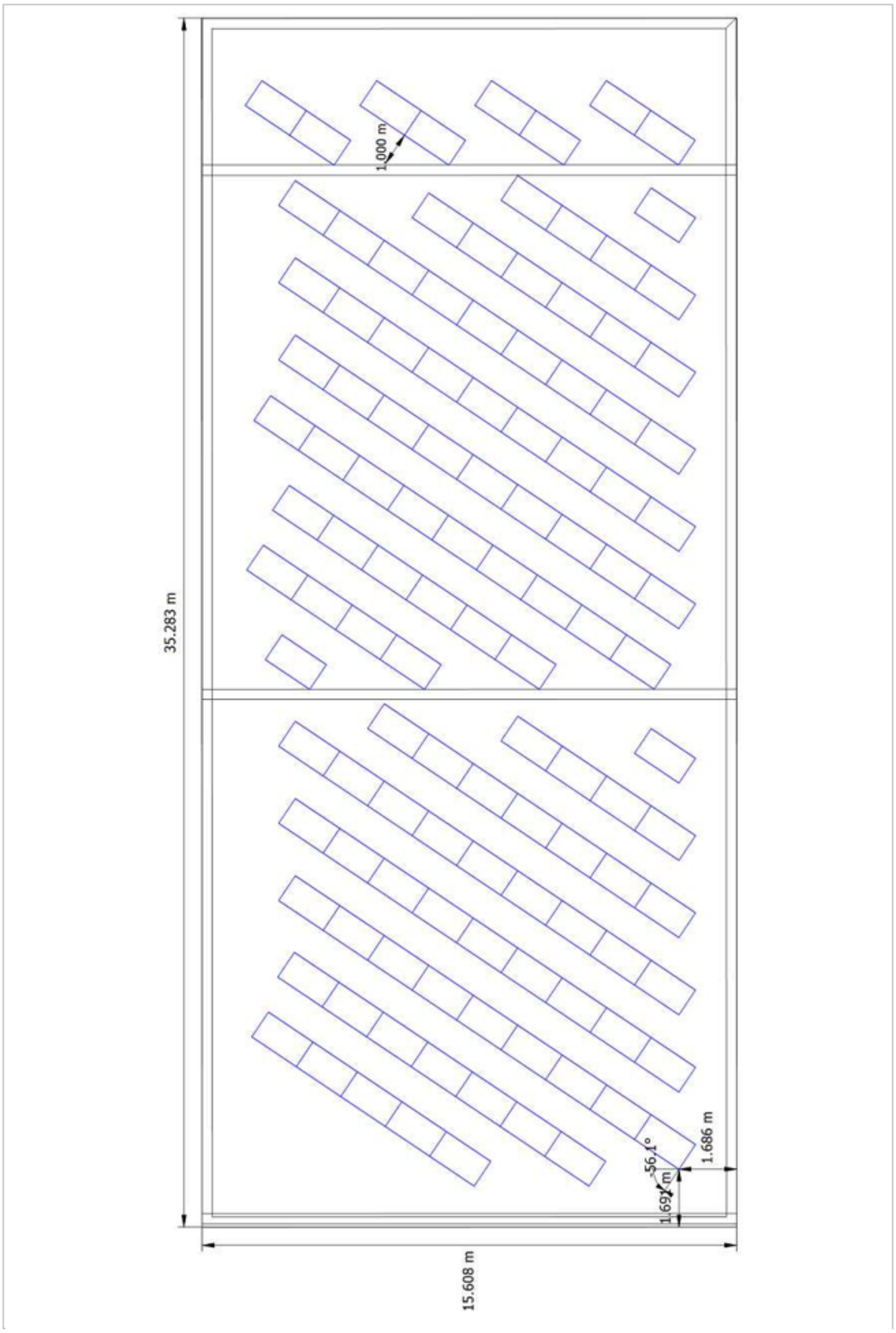
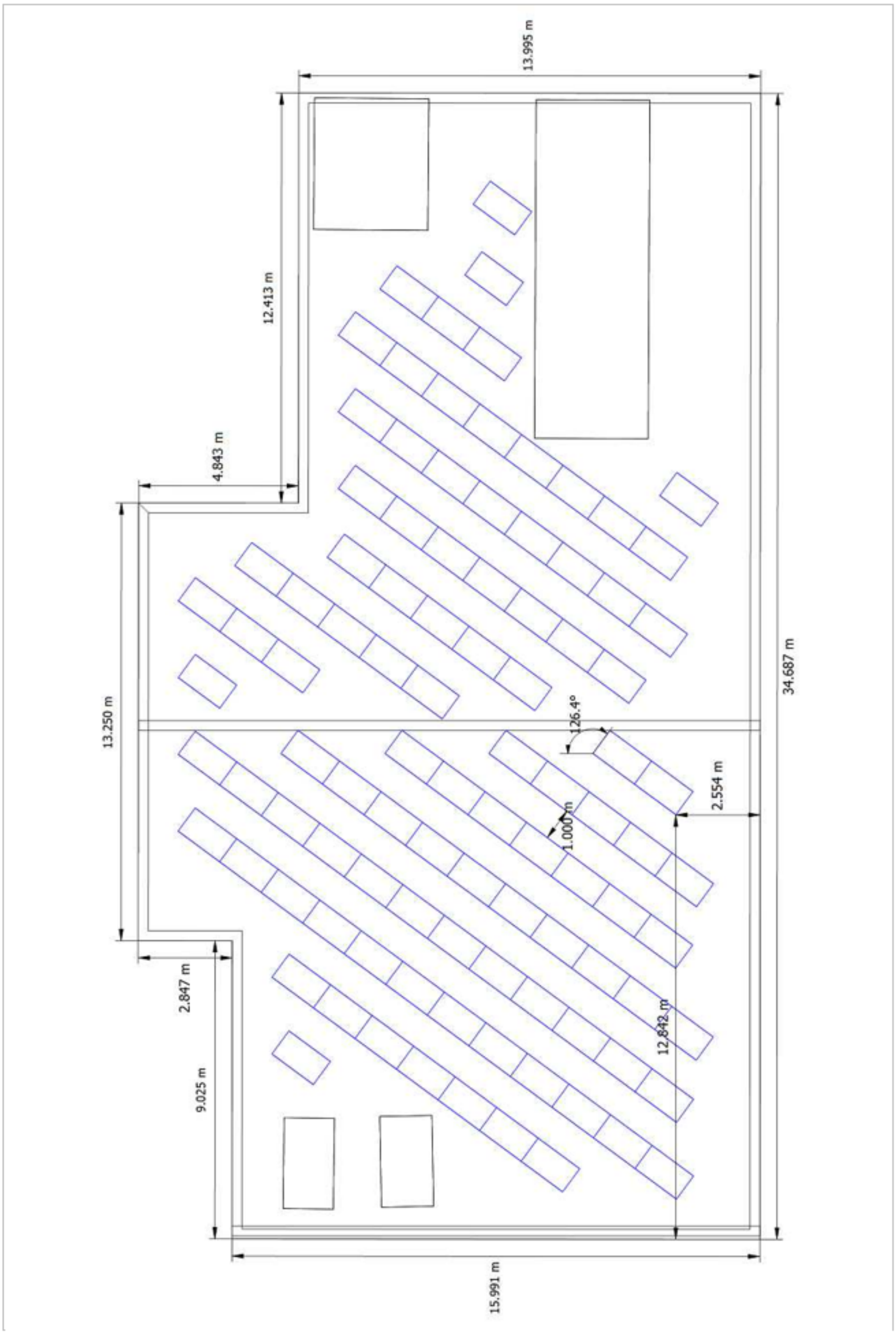
Arbitrary Building 06-Mounting Surface Southeast



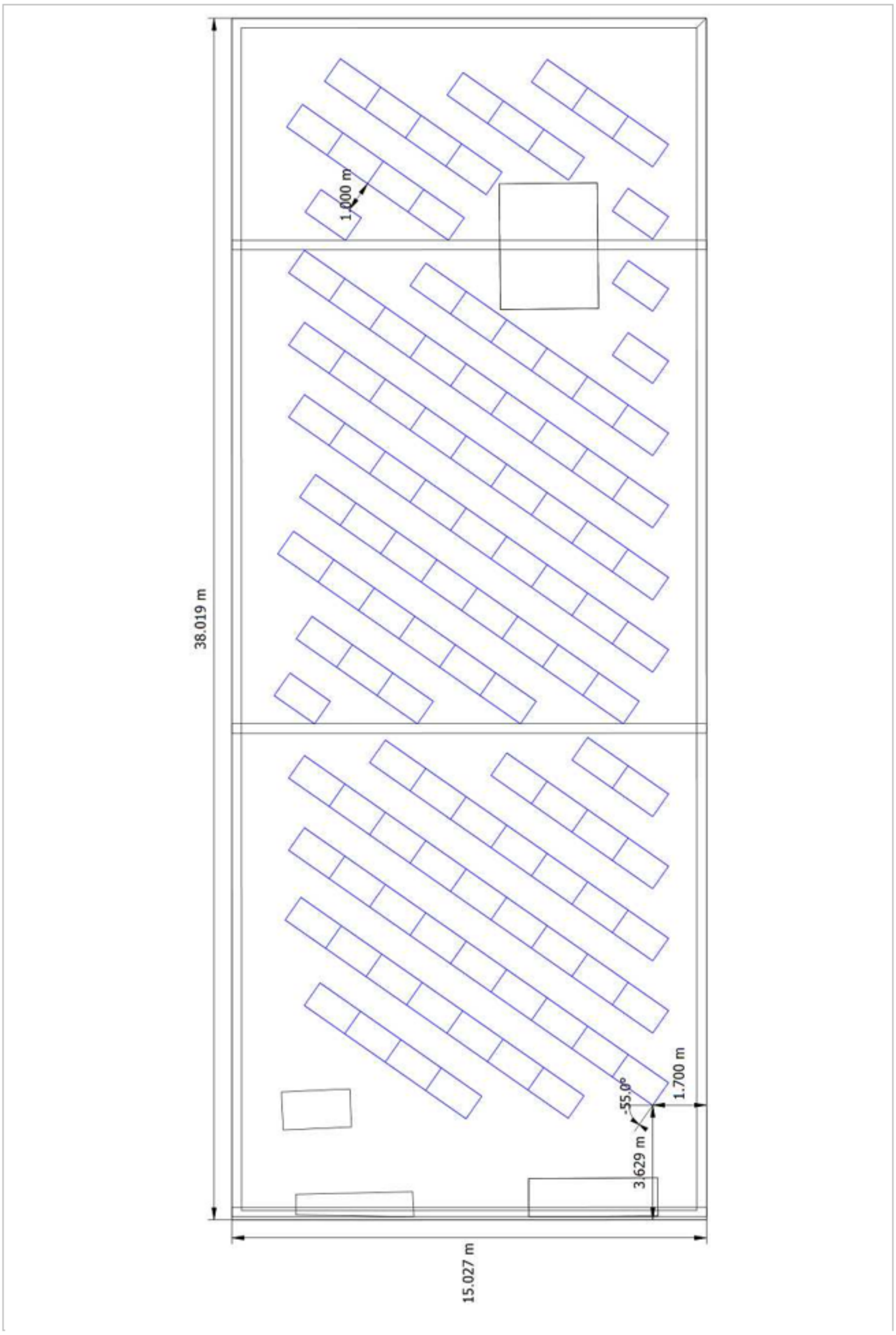
Building 09-Roof Area Southwest



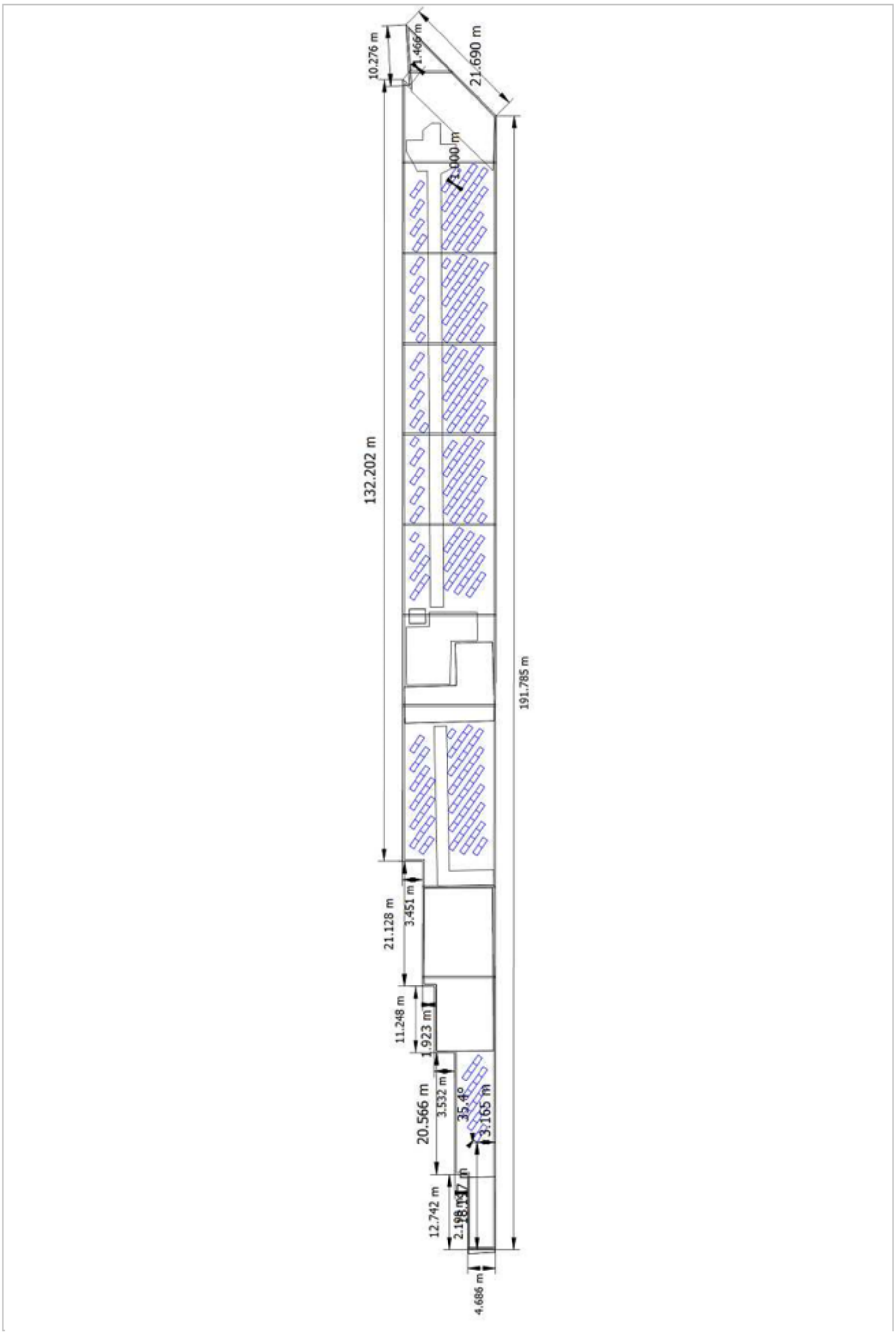
Arbitrary Building 18-Mounting Surface Northeast



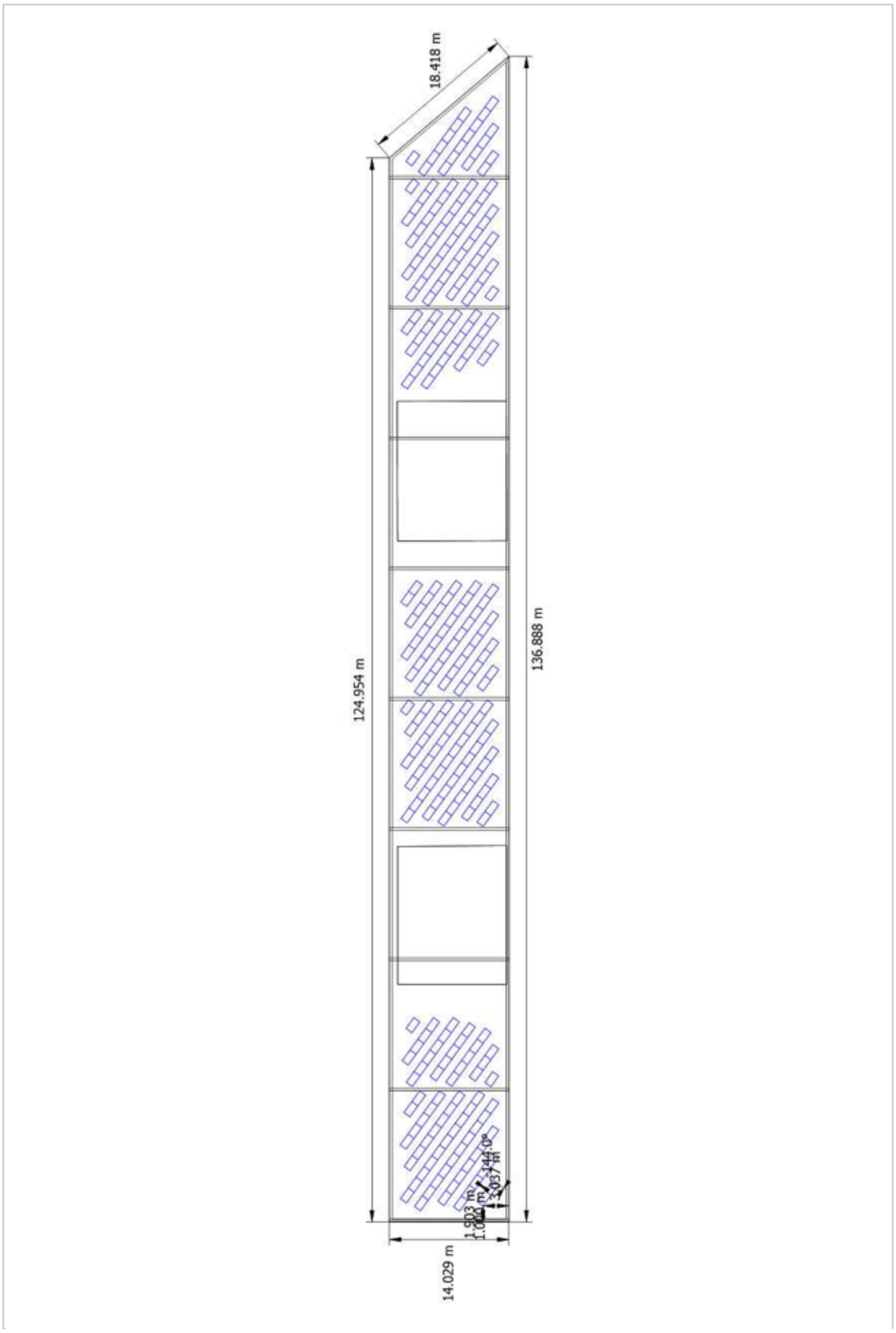
Building 08-Roof Area Southwest



Arbitrary Building 01-Mounting Surface Southeast



Arbitrary Building 07-Mounting Surface Northwest



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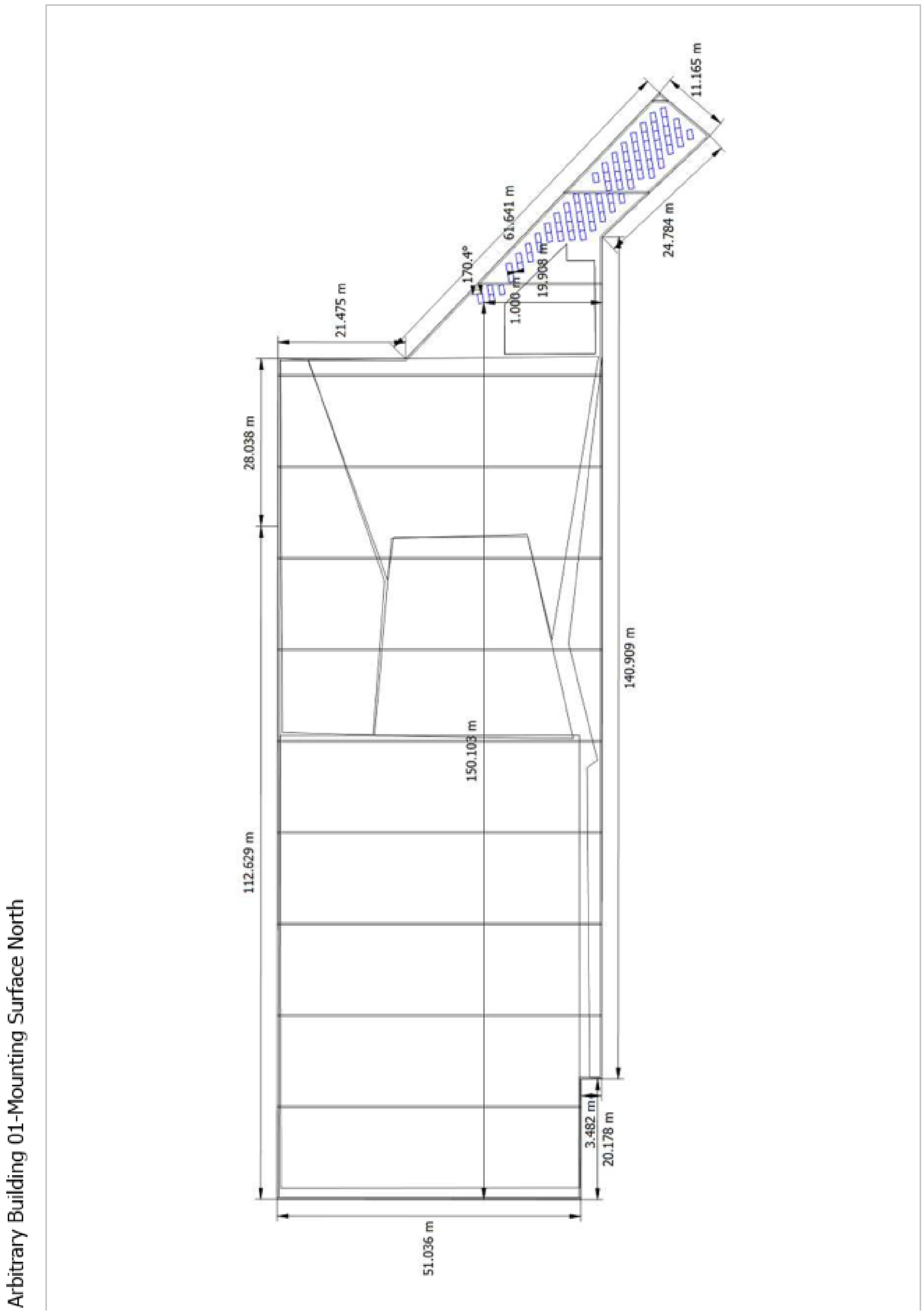
4.4.2. System II



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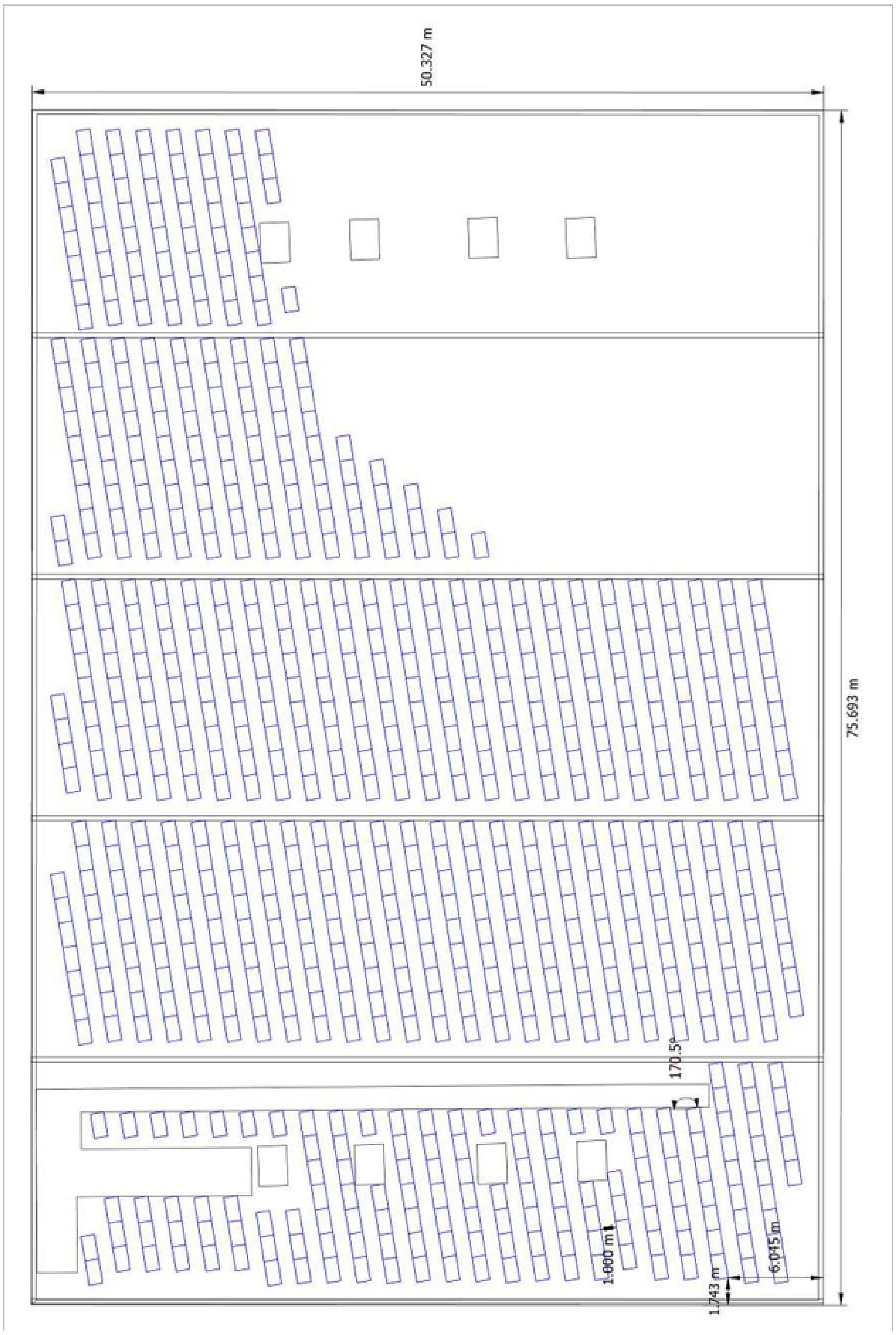
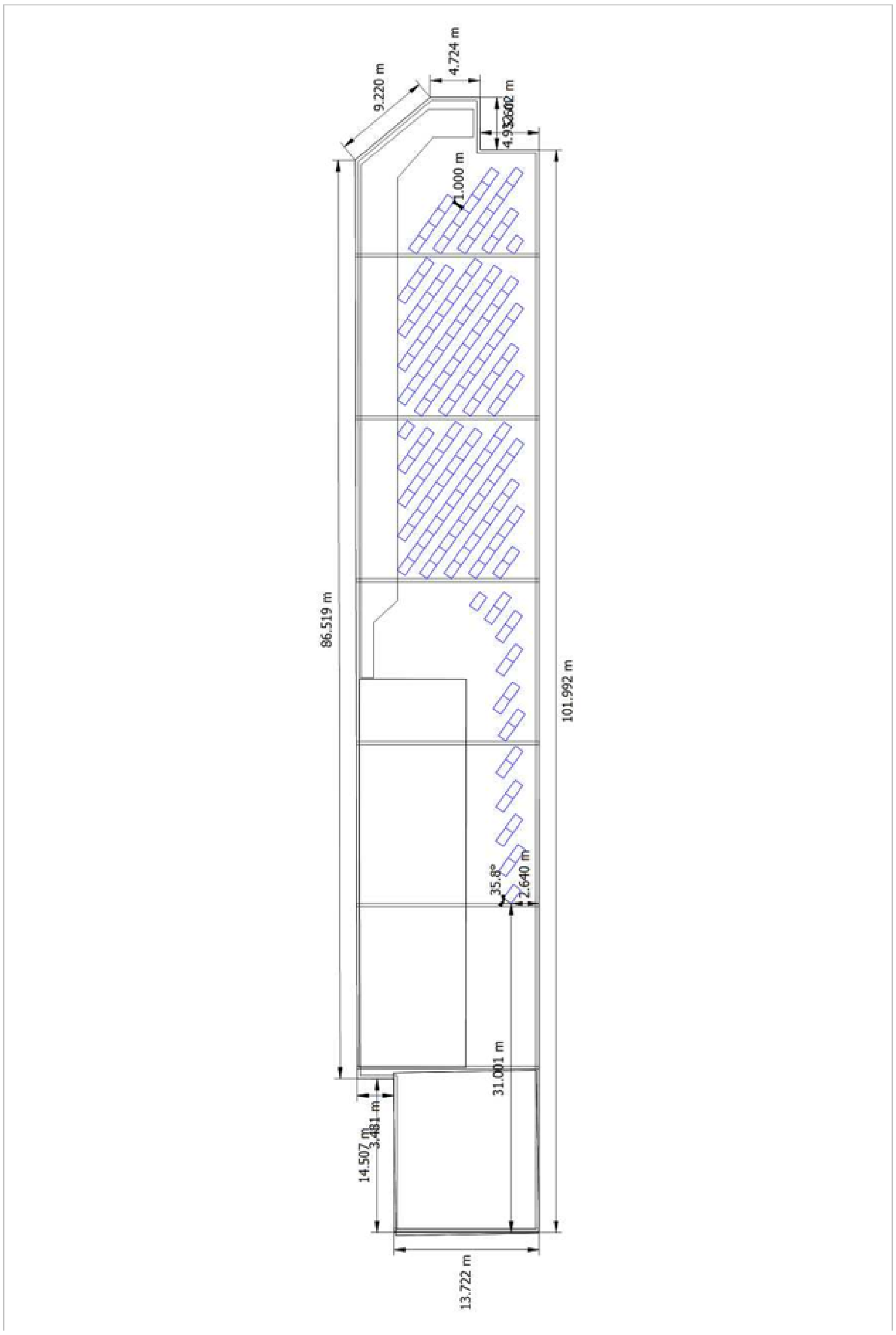
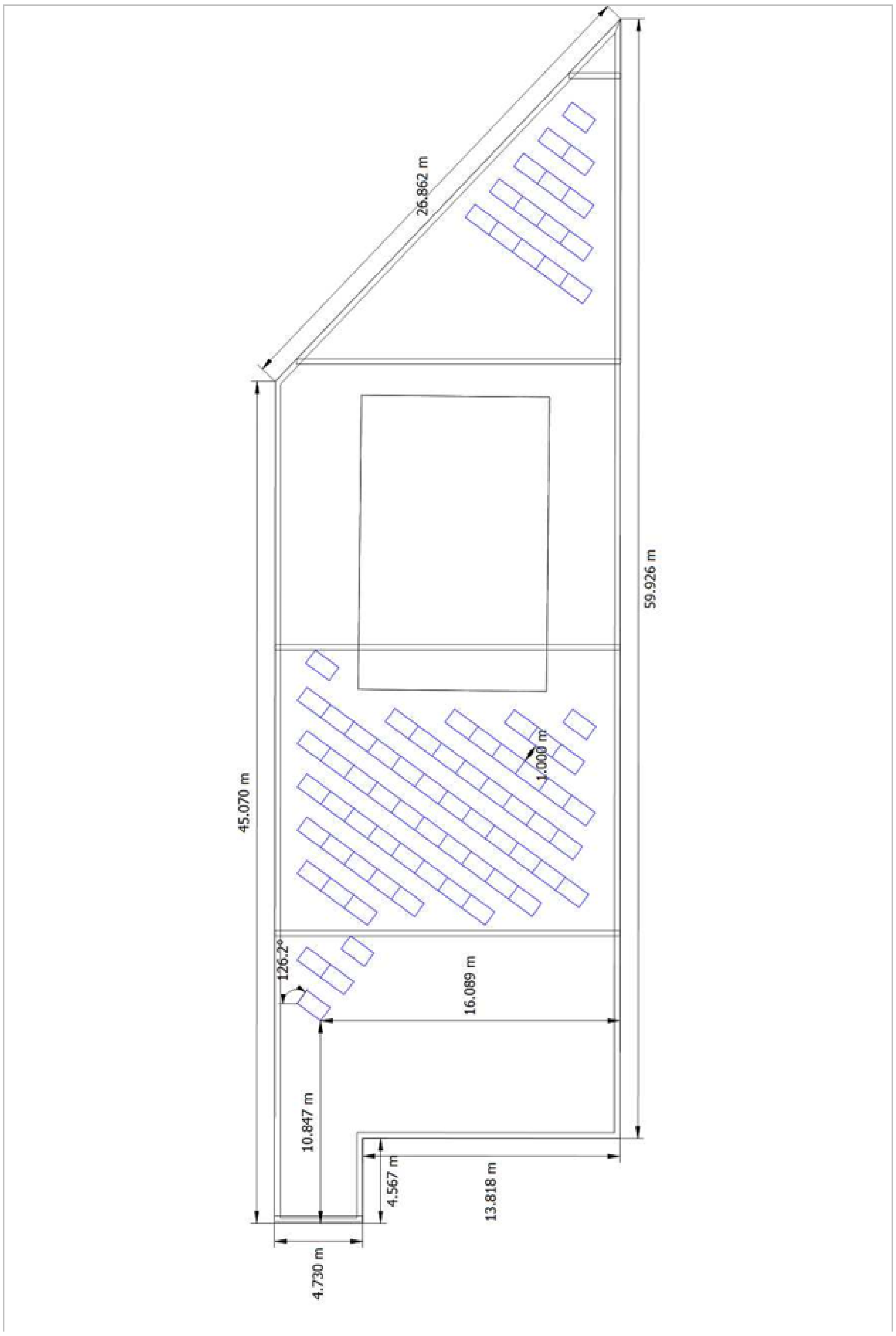
Arbitrary Building 02-Mounting Surface North



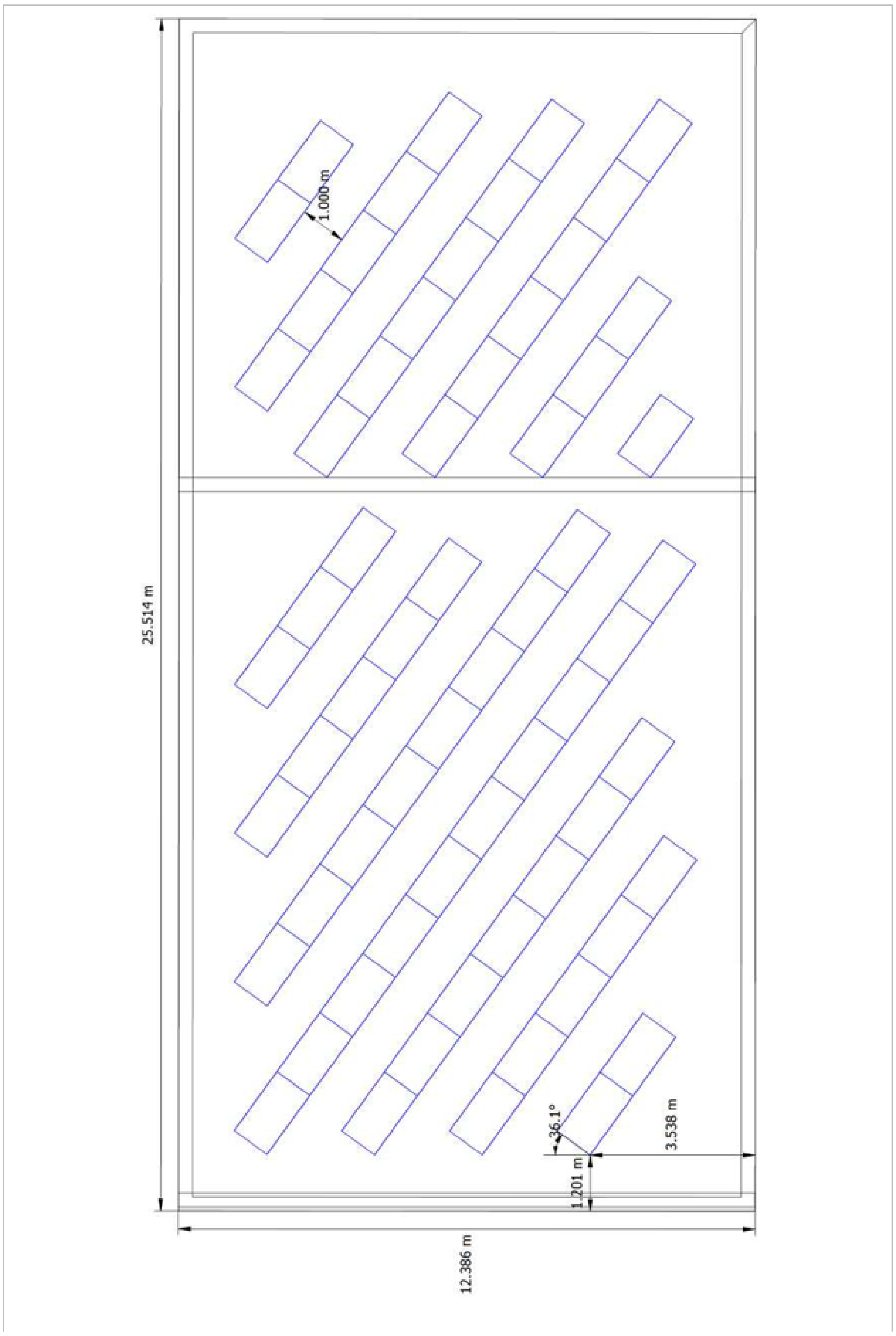
Arbitrary Building 09-Mounting Surface Southeast



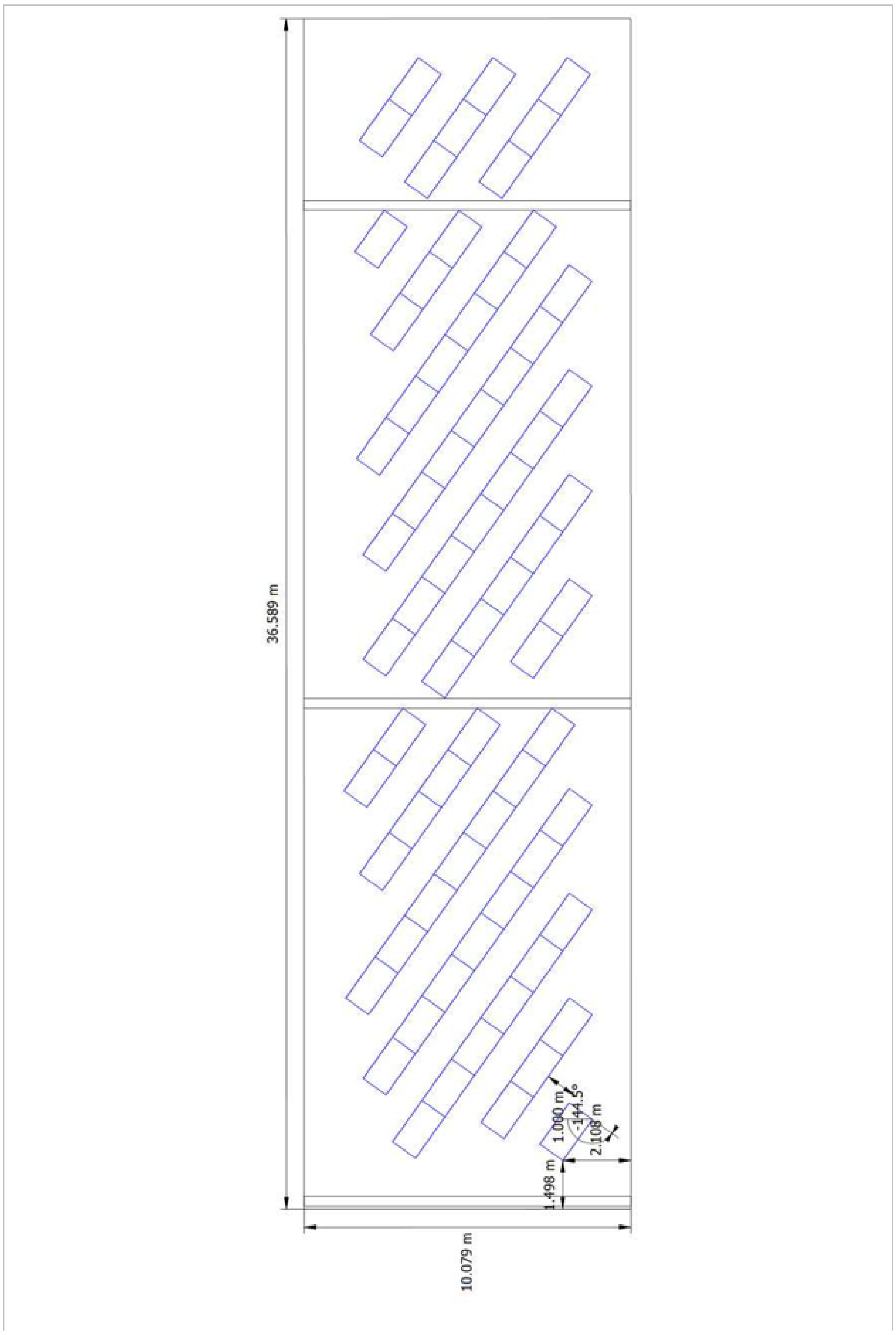
Arbitrary Building 08-Mounting Surface Northeast



Arbitrary Building 18-Mounting Surface Southeast



Arbitrary Building 11-Mounting Surface Northwest



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5. COSTS EXPLANATION

5.1. Investment Costs

According to NREL, as stated in [10] , investment costs for PV technology in 2017 have dropped by around 30% since 2010, which was mainly due to the reduction in inverter and module prices. Regarding commercial applications (size around 200kWp), these costs amounted to $1.8114 per installed Wp or €1.50109/Wp, while utility scale applications (100 MWp) have a cost of around $1.03/Wp or €0.8357/Wp. These costs are classified into different categories as: soft costs, which include land acquisition, sales tax, overhead costs, profit and installation costs; hardware, structural and electrical components; inverter and module costs. While the biggest costs correspond to soft costs and module costs.

The costs obtained through PVSol are between the range of values that have just been mentioned, which is coherent with the fact that the installation under analysis is also between their sizes. This confirms that the values provided by PVSol are reasonable and should be appropriate for our analysis.

5.2. Operation and Maintenance Costs

According to [11], these costs can be grouped as follows:

-Preventive maintenance, which includes routine inspections as specified in the terms of the contract. It is gaining increasing importance due to the fact that it reduces the likelihood of unplanned breakdowns or malfunctioning operation. However, they can increase the costs if not properly designed.

-Corrective maintenance, involves the repair of equipment after breakdowns or malfunctioning operation. Relying too much in this method implies low up-front costs but it also increases considerably the risk of component failure, which can eventually lead to higher costs.

-Condition-based maintenance, it consists on the prioritization of resources and maintenance according to real-time data for the anticipation of failures. However, it implies high upfront costs due to the software and hardware requirements of the monitoring equipment. This can also imply the risk of malfunctioning of the monitoring equipment and therefore lead to gathering non-reliable data.

Preventative Maintenance (PM)	
Panel Cleaning	Water Drainage
Vegetation Management	Retro-Commissioning†
Wildlife Prevention	Upkeep of Data Acquisition and Monitoring Systems (e.g., electronics, sensors)
Upkeep of Power Generation System (e.g., Inverter Servicing, BOS Inspection, Tracker Maintenance	Site maintenance (e.g., security, road/fence repair, environmental compliance, snow removal, etc.).
Corrective/Reactive Maintenance	
On-Site Monitoring	Non-Critical Reactive Repair**
Critical Reactive Repair* (high priority)	Warranty Enforcement
Condition-Based Maintenance (CBM)	
Active Monitoring—Remote and On-Site Options	Equipment Replacement (Planned and Unplanned)
Warranty Enforcement (Planned and Unplanned)	

Source: EPRI

† Retro-commissioning identifies and solves problems that have developed during the course of the PV system's life.

** Critical reactive repairs address production losses issues.*

*** Non-critical reactive repairs address production degradation issues.*

Fig. 5.1. Main PV Operation and Maintenance Costs [11]

According to [12], maintenance is key in PV technology projects, due to the fact that proper operation and maintenance implies an increase in efficiency, a reduction in O&M costs, ensuring safe operation and extending the lifetime of the system. Many studies have been carried out in order to provide an estimation of these costs:

The FEMP (Federal Energy Management Program) estimates O&M costs for PV systems greater than 1 MW to be around \$19 $\pm$ \$10/kWp/year (NREL). The EPRI (Electric Power Research Institute) suggests between 20-22\$/kWp/year is more appropriate. Other estimates of these costs are around 0.5% of initial cost per year (Wiser et al.) while there are others that specify costs according to the maintenance type: preventive maintenance, ranging from 0.04 to 0.08% of initial costs, while corrective and unplanned maintenance range from 0.01 to 0.22% of initial investment (Tucson Electric Power).

Regarding the last option, it is interesting to consider the different sources of maintenance. However, the downside of this option is that relating maintenance costs with initial investment could also be unfavourable to more expensive but more efficient equipment, that could be less prone to breakdowns and default.

The first source states that maintenance costs are proportional to the size of the system, which implies that bigger systems will incurr in greater costs. However, it should be taken into account that unit costs will be lower for greater systems due to economies of scale, given that fixed costs will be distributed among the kWp of the system. Therefore, as a relatively conservative approach 25\$/kWp or

20.28€/kWp will be considered.

5.3. Financing Costs

The financing conditions that have been considered for this analysis are the following: it has been assumed that the university will cover 40% of the total investment with private equity (own capital) and the remaining 60% will be externally financed through a long term loan with a maturity of 10 years at market interest rate.

According to the ECB the average interest rates for loans within the euro area for non-finantial corporations with a maturity of 10 years and with a value between 0.25 and 1 million euros are the following:

Period	Feb. 2017	Mar. 2017	Apr. 2017	May. 2017	Jun. 2017	Jul. 2017	Aug. 2017	Sep. 2017	Oct. 2017	Nov. 2017	Dec. 2017	Jan. 2018	Feb. 2018
Interest Rate [%]	1.58	1.63	1.62	1.64	1.59	1.62	1.66	1.68	1.61	1.63	1.60	1.65	1.63

TABLE 5.1. AVERAGE INTEREST RATES FOR LONG TERM LOANS FOR NON-FINANTIAL CORPORATIONS (ECB)

Therefore, the mean of these values has been used, obtaining 1.63%.

It should be noted that this option has been selected for the purpose of the analysis but many other financing mechanisms are also in place and are currently being implemented for other distributed PV applications. Among them, there are PPAs, crowd funding, renting and leasing. The former, would be the case where upfront costs would be (entirely or mostly) faced by a third party that would own the system, receiving in exchange the revenues from the sale of electricity generated by it.

5.4. Discount Rate

As discount rate the WACC has been employed, which according to Investopedia, it is calculated as follows:

$$WACC = \frac{E}{V} * R_e + \frac{D}{V} * R_d \tag{5.1}$$

Where
E is the Equity investment, which is the part of investment costs that is financed through own capital
D is the debt, defined by the loan

V is the total project investment costs, or E plus D
R_d, the Return on debt, which is the interest rate of the loan
and R_e is the Return on equity, which corresponds to the opportunity cost.

This last one would be the yield of the most profitable alternative that the university would have to compromise for investing in the solar installation. It has been assumed that this would consist on the dividends from holding shares in Endesa, which amount to 7% according to the Madrid Stock Exchange.

6. SCENARIO EXPLANATION - CHARGES AND COMPENSATION SCHEMES

For each scenario, the profitability of the investment has been evaluated. This has been done through the calculation of their NPV, IRR, LCOE and Payback time.

A summary of these scenarios as well as a detailed explanation of them will be presented below.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**	**Scenario 5**
Compensation of Surplus Electricity Injected into the Grid	Wholesale Price	Wholesale Price	Wholesale Price	Feed-in-Tariff	Retail Price (Net Metering)
Backup Charges	Variable	Variable	None	None	None
Other Support Mechanisms	None	Investment Compensation	None	None	None

TABLE 6.1. SUMMARY OF SCENARIOS

6.1. Scenario 1

This is the scenario under the current Spanish regulation. Taking into account that the installation is greater than 100 kW, this would correspond to a type II system. This implies that the surplus of electricity injected into the grid is remunerated at the wholesale price minus a generation tax of 7 % of revenues from sold electricity [Law 15/2012] and a grid access charge of 0.5 euros per exported MWh [RD 1544/2011]. Moreover, backup charges for self-consumption apply; in this case, as battery storage is not considered, only variable charges apply, amounting to 0.0194 euros per self-consumed kWh [RD 900/2015].

The annual costs for year j under this scenario can be obtained as follows:

$$C_{1j} = PV\_OM_j + \sum_{i=1}^{8760} (EG\_L_{ij} * Ep_{ij}) + \sum_{i=1}^{8760} (VBC * PV\_L_{ij}) + P_{capj} + I_j - \sum_{i=1}^{8760} [(1-\lambda) * (WP_{ij} - \alpha) * PV\_G_{ij}] \quad (6.1)$$

where:

PV_OM are the operation and maintenance costs of the PV system

EG_L is the hourly energy purchased from the grid to cover the load
Ep_i is the hourly price of electricity
VBC is the variable backup charge for self-consumption
PV_L_i is the hourly energy generated by the PV system that is used to cover the load
P_{cap} is the annual cost of contracted capacity
λ is the generation tax
WP_i is the hourly wholesale electricity price
α is the grid access charge
PV_G_i is the hourly energy generated by the PV system that is sold to the grid
I are the interest payments

6.2. Scenario 2

This scenario is the same as the previous one but considering the application of the specific remuneration scheme as per Order ETU/315/2017, which will be explained below.

6.2.1. Specific Remuneration System

According to the article 14.7 in Law 24/2013 regulating the electric sector, the government can establish a tender ("Régimen Retributivo Específico") for renewable energy sources, cogeneration and waste in order to meet energy targets set in European Union Directives or in case their introduction implies a reduction in costs or in energy dependence.

Currently, 17.3% of Spain's consumption comes from renewable energy sources. The expected increase in consumption by 0.8% by 2020, together with the European target of 20% consumption covered through renewable resources by 2020, (as stated in the European Directive 2009/28/CE from the European Parliament), makes it necessary to introduce support mechanisms for RES, so as to encourage an increase in the penetration levels of these technologies.

Due to this, a tender was opened in 2017 for the introduction of 3000 MW of renewable energy, the terms of which are set in the Royal Decree 359/2017. Such tender is applicable to new installations of renewable energy resources, cogeneration and waste in the peninsular electric system.

The allocation mechanism of the tender, which is regulated through the Royal Decree 359/2017, on the 31^{st} of March, is performed through energy auctions where the product bidders compete for the right to perceive a specific remuneration scheme that is offered as a reduction in the standard value of the initial investment, which varies according to the type of technology.

The allocation mechanism is based on the selection of those installations that will have a lower cost for the network. This cost is computed for each installation, and it is defined as the quotient between return on investments and the number of equivalent hours of operation. These quotients will then be ordered in increasing order and those bids with lower unit cost will win the tender, until the maximum capacity (set in the tender) is reached. In 2017, the limit capacity for the first tender was 3000 MW, as established in the third article of the Royal Decree 413/2014, on the 6^{th} of June.

The marginal cost of each technology will correspond to that of the last bid that won the tender within that same type of technology and it will be used to calculate their specific remuneration.

The entity in charge of administrating the tender is OMIE, while the organism in charge of supervising it is the CNMC. The applicable compensation parameters for new PV projects depending on year of granted permsission for installation are the following:

Year	Compensation [€/ installed kWp]
2017	39.646
2018	38.480
2019	36.908

TABLE 6.2. INVESTMENT COPENSATION FOR NEW INSTALLATIONS AS PER ORDER ETU/315/2017

The applicable compensation for 2017 will be selected as it is the closest to 2016, which is the year from which most of the data was obtained (load, electricity bills...).

The annual costs for year j under this scenario can be obtained as follows:

$$\begin{aligned} C_{2j} = PV\_OM_j + \sum_{i=1}^{8760}(EG\_L_{ij} * Ep_{ij}) + \sum_{i=1}^{8760}(VBC * PV\_L_{ij}) + P_{capj} + I_j \\ - \sum_{i=1}^{8760}[(1-\lambda) * (WP_{ij} - \alpha) * PV\_G_{ij}] - RI_1 * CPV \end{aligned} \tag{6.2}$$

where:

RI_1 is the investment compensation applicable the first year
CPV is the total installed capacity of the PV system

6.3. Scenario 3

This scenario is the same as the first one but without considering grid access charges, the generation tax and the variable backup charge.

Therefore, annual costs per year j are calculated as follows:

$$\begin{aligned} C_{3j} = PV\_OM_j + \sum_{i=1}^{8760}(EG\_L_{ij} * Ep_{ij}) + P_{capj} + I_j \\ - \sum_{i=1}^{8760}[(1-\lambda) * (WP_{ij} - \alpha) * PV\_G_{ij}] \end{aligned} \tag{6.3}$$

6.4. Scenario 4

In this case, a feed in tariff has been selected as remuneration mechanism. No grid backup charges for self-consumption are considered.

Annual costs are calculated as follows:

$$C_{4j} = PV\_OM_j + \sum_{i=1}^{8760}(EG\_L_{ij} * Ep_{ij}) + P_{capj} + I_j - \sum_{i=1}^{8760}[FiT_j * PV\_G_{ij}] \tag{6.4}$$

where FiT is the Feed-in-Tariff

6.5. Scenario 5

In this case, a Net Metering compensation mechanism without grid backup charges is considered. As has been explained in previous sections, this mechanism consists on remunerating electricity injected into the grid at retail price. Credits are awarded for electricity injections, giving the right to consume that amount of energy from the grid at other points in time.

Annual costs are defined as:

$$C_{5j} = PV\_OM_j + \sum_{i=1}^{8760} (EG\_L_{ij} * Ep_{ij}) + P_{capj} + I_j - \sum_{i=1}^{8760} [Ep_{ij} * PV\_G_{ij}] \qquad (6.5)$$

7. RESULTS FROM SIMULATION

In this section, the main results from the techno-economic tool developed through Matlab will be presented.

A summary of all employed scenarios in the analysis is available in table 6.1 so as to familiarise the reader with them, as these will often be referred to by their name, “Scenario X”, in this section.

The first and main finantial parameter to be taken into account in the analysis is the Net Present Value. Figure 7.1 shows the results of the calculation of the net present value per scenario for given discount rates.

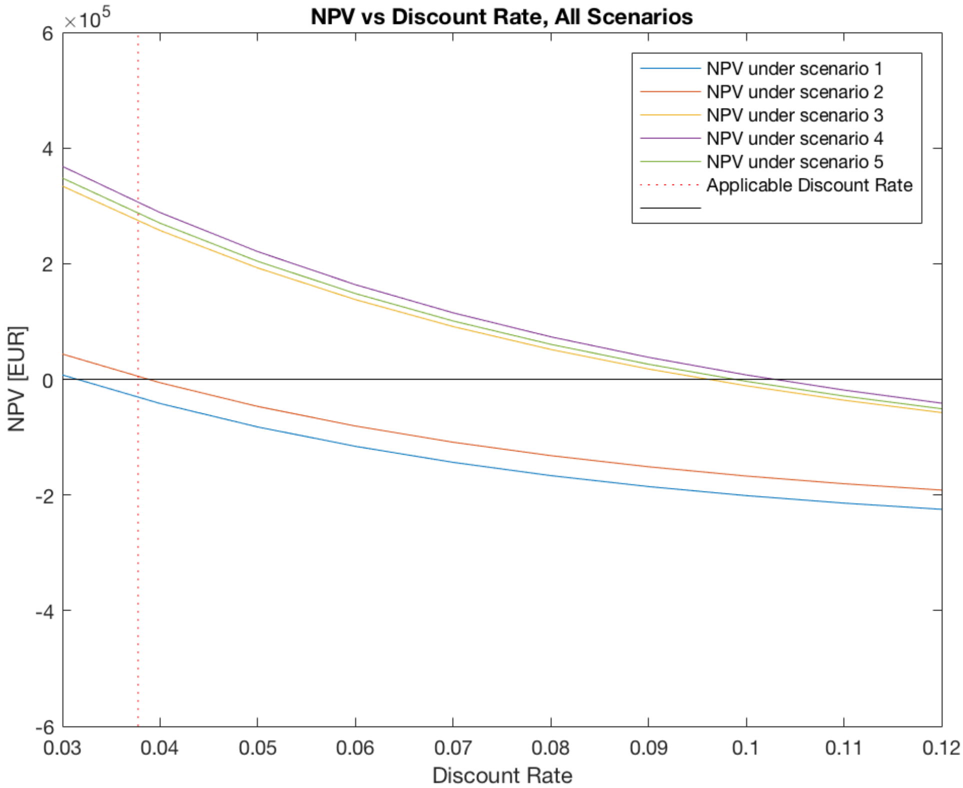

Fig. 7.1. Net Present Value against Discount Rate

There are several benefits from plotting NPV against the discount rates; first, it offers a visual display of the IRR, defined as the discount rate at which NPV is zero. Therefore, it corresponds to the intersection of NPV curves with the x axis.

Secondly, by displaying the ”current discount rate”, which is the discount rate employed in this analysis, defined by the WACC, it enables to visually see which investments are profitable and which ones are not. This is done by comparing their IRR with the current discount rate, taking into account that those scenarios with an IRR greater than the current discount rate are scenarios under which the investment would be profitable while those with an IRR lower than it, would not.

In our case, it can be seen that only an investment under scenario 1 would not be worth investing in.

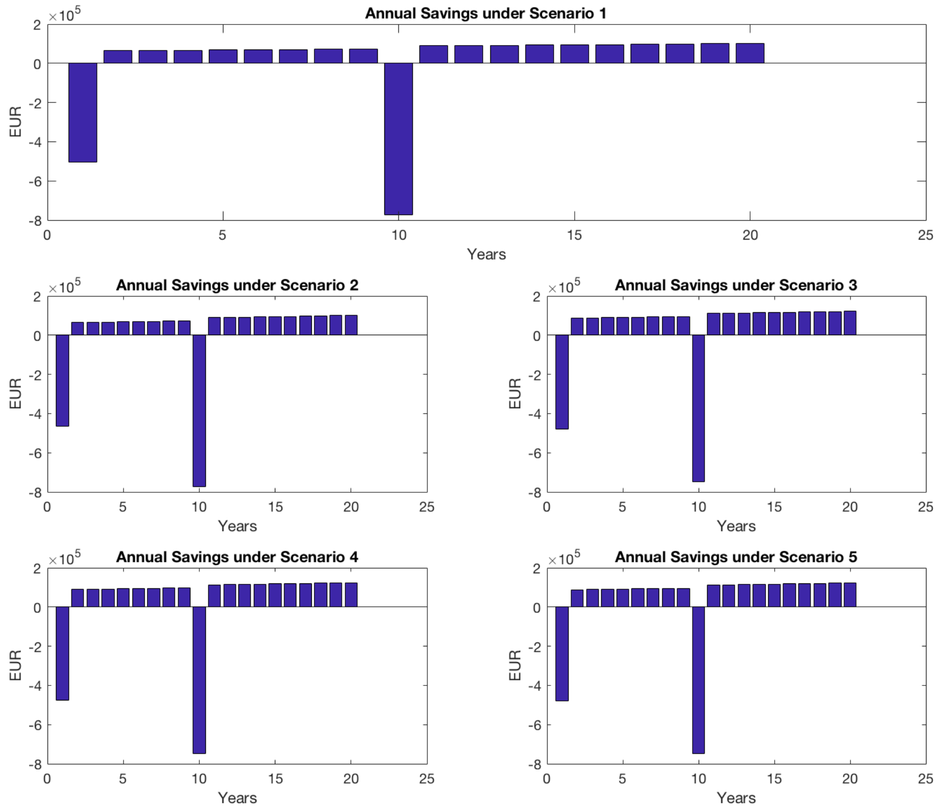

Fig. 7.2. Annual Savings per Scenario

Moreover, figure 7.2 shows the savings per year for each scenario. There are several aspects that can be noticed from it.

The general idea is that upfront costs will take place the first year and revenues and savings will be generated as a result of this investment for the forthcoming years, taking into account that the principal must be repaid by the 10th year. However, it can be seen that investment costs are considerably higher than the savings that will be generated by the investment. Which makes it convenient to evaluate these savings separately in more detail, as will shortly be done through figures 7.3 to 7.7.

In the following graphs, the origin of these savings will be reviewed. From figures 7.3 to 7.7, it can be seen that these savings are mainly generated as a reduction in the electricity bill due to self-consumption, in fact, revenues from grid exports conform an average of 6.1687 % of total savings, considering scenarios 1 to 5. This is due to the fact that most of the electricity production of the PV plant is consumed locally rather than being exported, being 98.4885% of PV generation consumed locally and only the remaining 1.5115%, exported.

This is convenient from both a technical and economic perspective. The former, given that consuming the generated electricity locally implies lower transmission losses; and the latter, given that all export tariffs are lower than the retail price of electricity, unless a net metering mechanism is applied. As for FiTs, when applicable, they are usually limited in terms of the years that they can be applied as well as the amount of grid exports that can be compensated under them, usually requiring a certain percentage of electricity production to be destined to self-consumption. As was mentioned in section 2.2.3, "remuneration schemes can have a limit in time (10, 20 years) such is the case of the FiTs in China, Denmark, France and Germany".

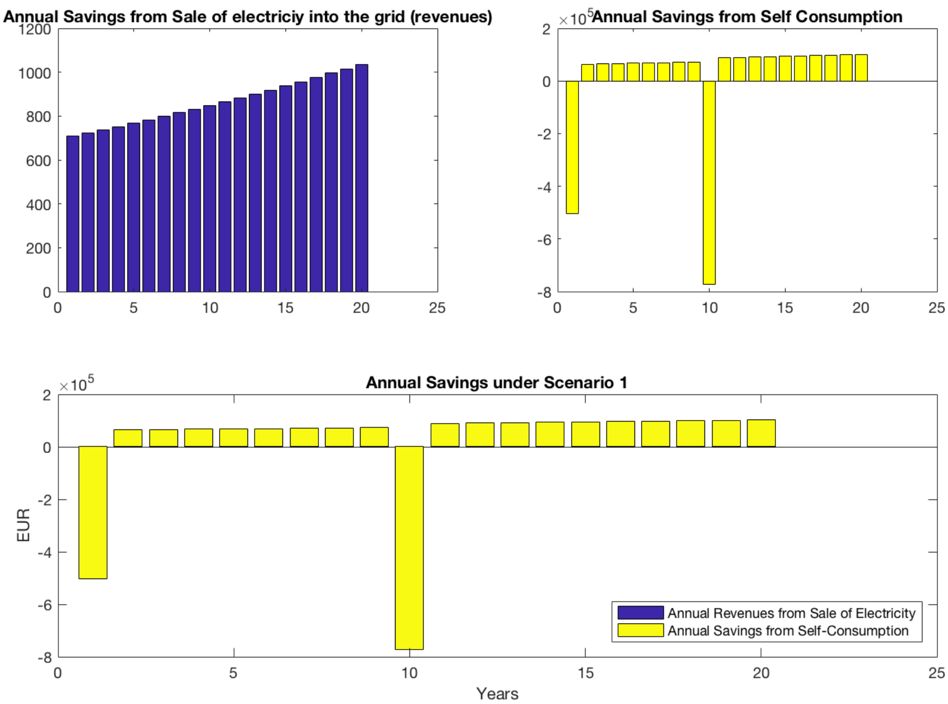

Fig. 7.3. Detailed Annual Savings under Scenario 1

In the second scenario, represented through figure 7.4, the investment compensation granted for the first three years can be seen, added to the savings from self- consumption.

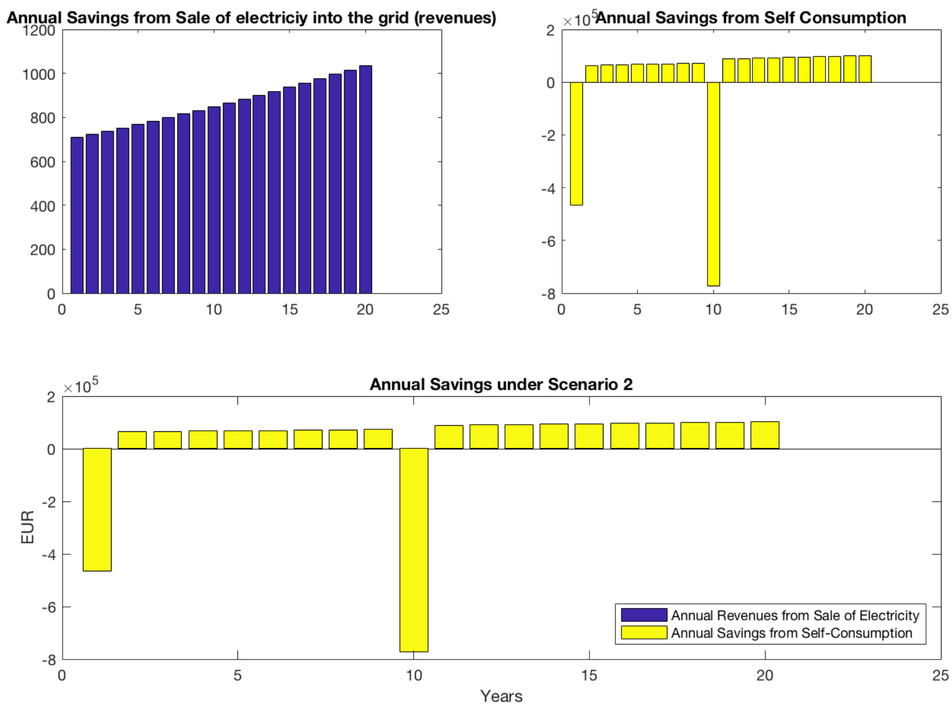

Fig. 7.4. Detailed Annual Savings under Scenario 2

In figure 7.5, an increase in revenues from grid exports can be seen. This 8.5378% increase relative to scenario 1, is due to the fact that the grid access charge and the generation tax are no longer considered. Moreover, savings from self-consumption have increased by 24.04% relative to scenario 1, which is due to the fact that variable backup charges on self-consumption have been removed, which will be the case for scenarios 3, 4 and 5.

Scenario 4, referred to by figure 7.6, shows an increase in revenues from the sale of electricity to the grid, amounting to a 280% increase relative to scenario 1. This represents the most profitable compensating mechanism as it generates the greatest revenues, followed by scenario 5, (figure 7.7), which shows an increase of 118.92% in this figure.

Moving on to cumulative savings, figure 7.8, it can be noticed that scenarios 1 and 2 have the same slope. This is coherent with the fact that both have the same compensating mechanism for the surplus of electricity sold to the grid and both consider the application of the variable backup charge on self-consumption. The difference between them corresponds to the investment compensation of-

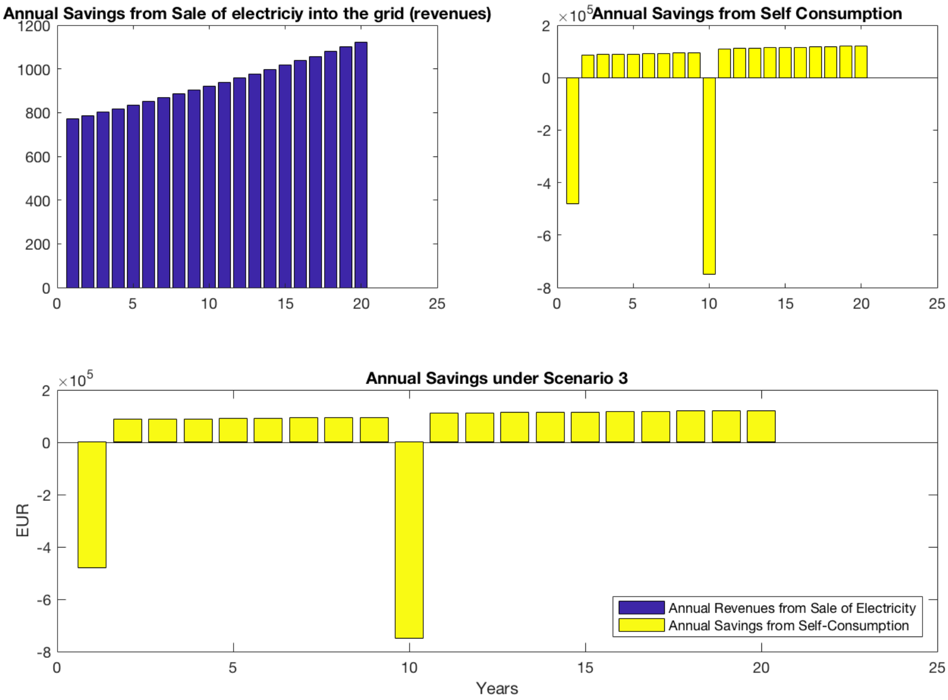

Fig. 7.5. Detailed Annual Savings under Scenario 3

fered through tenders.

Regarding the other 3 scenarios (3, 4 and 5), it can be observed that there are no major differences among their cumulative savings. This is aligned with the fact that the main part of savings comes through self consumption of the generated electricity rather than by the revenues of selling surplus electricity to the grid, and this parameter is equal for the three scenarios. The major difference between these three and the first two is therefore, the payment of the variable backup charge on self-consumption, which has a bigger impact than the applicable compensation mechanism for grid exports.

Moreover, savings are more moderate during the first 10 years, due to the payment of interests. Cumulative savings increase with a steeper slope once the principal has been repaid and no more interests are owed.

Furthermore, it should be noted that the intersection of this graphs with the x axis determines the Payback time, which is the time at which enough revenues have been generated from the system to recover the initial investment.

Finally the LCOE will be analyzed. According to [13], discounted LCOE can be calculated as follows:

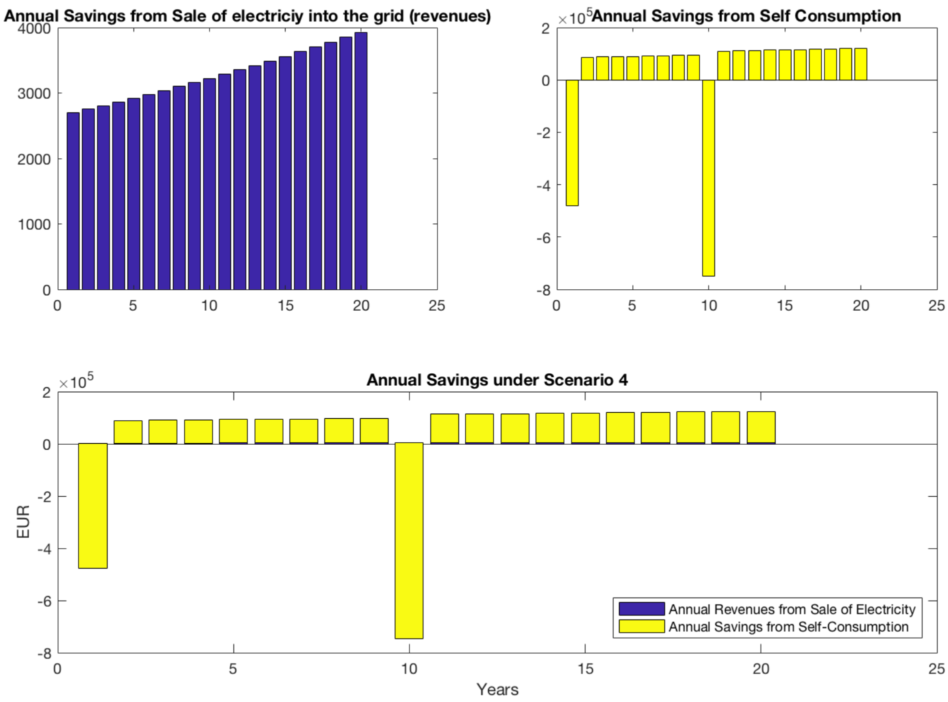

Fig. 7.6. Detailed Annual Savings under Scenario 4

$$LCOE_{Disc} = \frac{PVal\_Costs}{PVal\_Energy} = \frac{\sum_{j=1}^{20}[Costs_j * disc\_factor_j]}{\sum_{j=1}^{20}[E_j * disc\_factor_j]} \tag{7.1}$$

where
$PVal\_Costs$ is the present value of costs
$PVal\_Energy$ is the present value of the energy generated by the system
$Costs_j$ are the annual costs of operating the system
$disc\_factor_j$ is the applicable discount factor for each year, which is calculated as follows:

$$disc\_factor = \frac{1}{(1+r)^j} \tag{7.2}$$

where
r is the applicable discount rate
and j is the corresponding year, for each of the 20 years considered under this analysis.

Using discounted LCOE makes it possible to compare the costs produced by

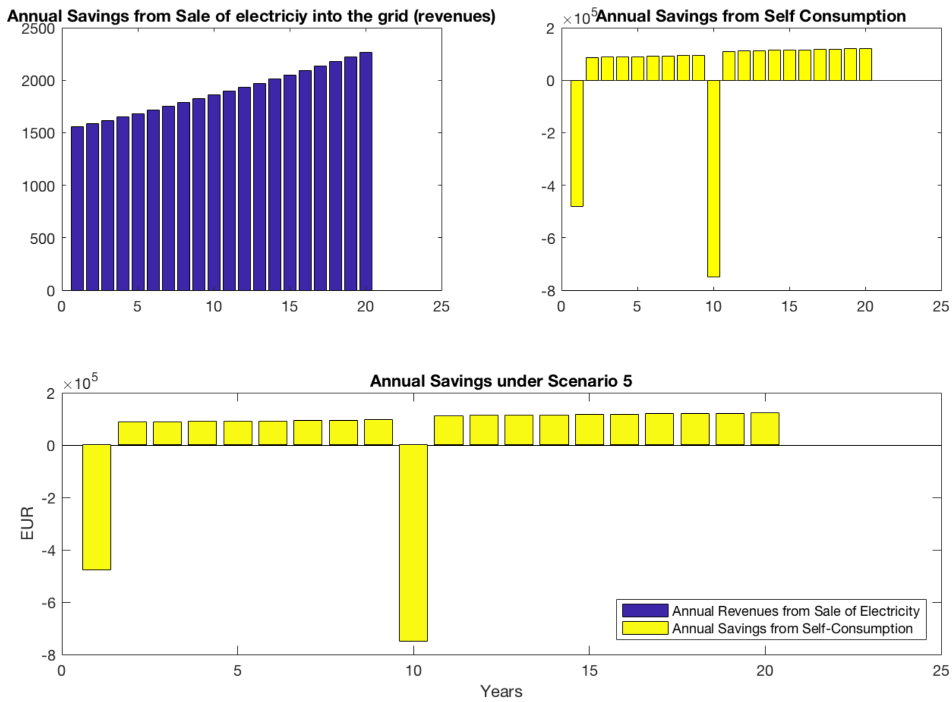

Fig. 7.7. Detailed Annual Savings under Scenario 5

a system with the energy generated by it, taking into account when were these costs produced and when was this energy generated, therefore, taking into account the time value of money.

The overall discounted LCOE has been calculated for the PV plus grid system. In figure 7.9, the calculation of this parameter for each scenario under given discount rates is displayed.

It should be noted that the main value of LCOE is to offer a comparison between scenarios, rather than providing an absolute figure. That is why it has been deemed more convenient to calculate the LCOE as a function of the discount rate to evaluate its sensitivity to changes in this factor.

LCOE from the base scenario has also been included, which allows to compare under which discount rates is the discounted LCOE of each scenario lower than the base case where no investment is considered.

The first noticeable aspect is that the same pattern as that in the NPV curve can be observed. Scenarios are ordered according to increasing LCOE, where scenario 1 is the one with the highest cost, followed closely by scenario 2 with a decrease in LCOE of around 0.20%. Next, come scenarios 3, 5 and 4 with a de-

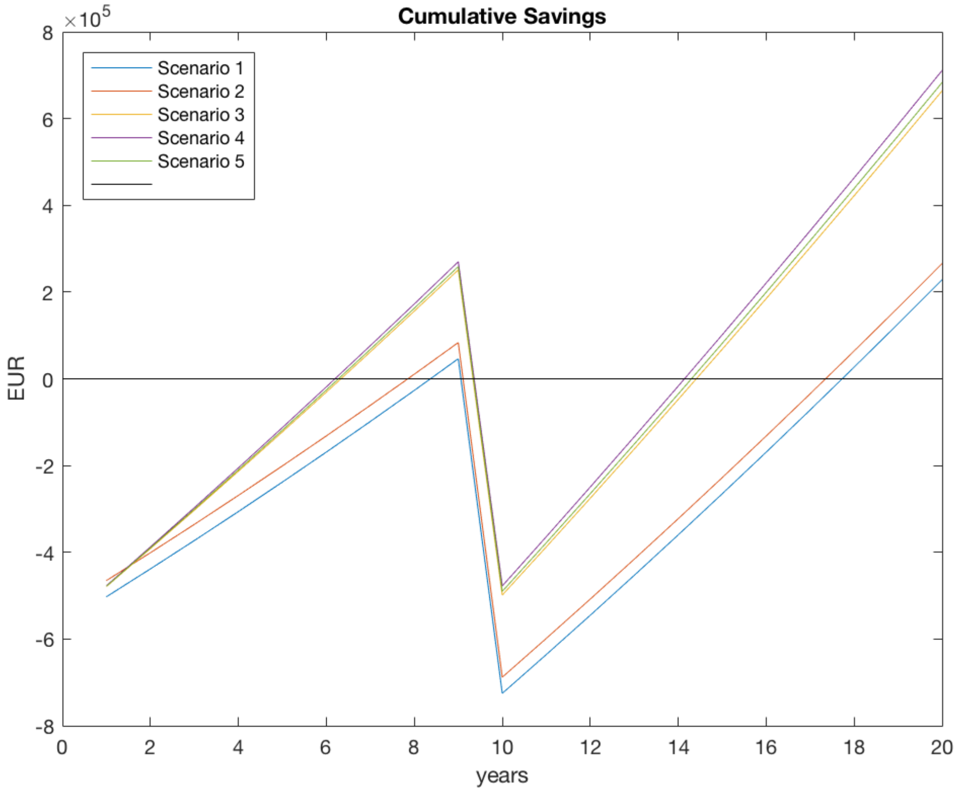

Fig. 7.8. Cumulative Savings

crease in LCOE between 1.6 to 1.8%, being the latter the one that represents the most profitable scenario. This results confirm the conclusions derived from the NPV graph regarding profitability.

Furthermore, by displaying the current discount rate in the same graph, it can visually be seen under which scenarios does the investment result in are more expensive alternative than the base scenario. That is under scenario 1, which is the only scenario under which the investment would not be economically feasible. The LCOE of the solar plus grid system under all regulatory scenarios is lower than that of the grid itself, with an LCOE of 0.1449€/kWh, except under scenario 1, with an LCOE of 0.1451 €/kWh.

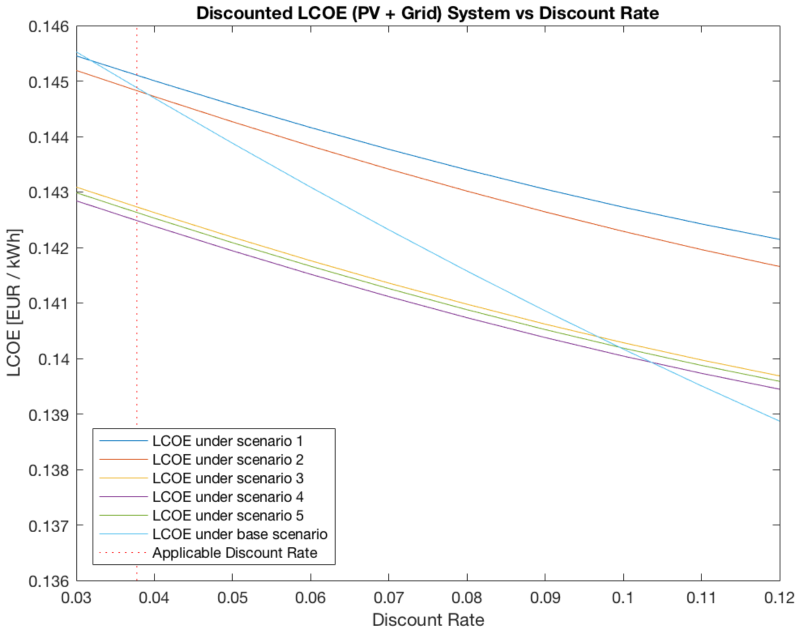

Fig. 7.9. Discounted LCOE (PV + Grid) System vs Discount Rate

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
NPV [€]	-30726.14	5184.25	274552.56	306269.61	287449.58
IRR [%]	3.1520	3.8802	9.6137	10.2894	9.8796
LCOE [€/kWh]	0.1451	0.1448	0.1427	0.1425	0.1426
Payback Time [years]	17.73	17.35	14.41	14.14	14.30

TABLE 7.1. SUMMARY OF RESULTS

8. CONCLUSIONS

As anticipated by [1], low returns are expected for a distributed photovoltaic installation under the current Spanish regulation for the commercial sector. In this case, IRR was found to be 3.15% and NPV was negative, meaning the investment would not be profitable, provided these conditions are present.

The application of the investment compensation granted through the tenders, makes the investment profitable, having a positive NPV, however, at a low return (3.88%).

Moreover, it was observed that a feed-in-tariff would be the most profitable compensating mechanism, with around a 280% increase in revenues from grid exports compared to the case of wholesale price subject to a generation tax and a grid access charge. It would be followed by a net metering mechanism, where the surplus of electricity would be remunerated at the retail price, which would result in an increase in revenues from grid exports by around 120%.

However, the remunerating mechanism does not have the biggest impact in the final savings, given that less than 2% of generated electricity is sold to the grid. Furthermore, FiTs are not sustainable in the long term, but rather conform a short term support mechanism for renewable energy in the form of a subsidy that implies a high cost for the government. In fact, countries such as the UK are revising them and they are likely to be removed by 2019. The UK Treasury announced no new low carbon electricity levies would be implemented until 2025, which implies that the FiT will not be replaced once current FiT legislation ends, as was made clear by Brighton Energy Cooperative in [26].

It can be seen how the presence of variable backup charges on self-consumption has a considerable negative impact, especially in PV installations of this character, where most of produced electricity is self-consumed. In fact, as was presented in this study, around a 24% increase in savings would occur, should this charge be removed.

Net billing at wholesale price without backup charges constitutes the most reasonable mechanism as it creates competitive equality among energy producers, giving priority to the most efficient and cheapest technologies.

According to UNEF, instability in regulations constitutes a very severe problem, this is not only due to the fact that it dissuades potential investors but also because it hinders financing conditions for those who decide to invest in this technology.

So as this study proves, the development and deployment of distributed PV for self-consumption will be strongly dependent on the applicable regulations, even though the advances in technology and the decrease in the cost of components can reduce their overall impact.

9. FURTHER RESEARCH AND OPPORTUNITIES

In the following section, futher research and opportunities for this university are presented.

9.1. Microgrids

As has been previously discussed, the current electricity network is based on a one-directional energy flow, where the electricity is mainly generated by large central generators that have considerably high pollutant emissions and where active participation of consumers is negligible. However, increasing electricity costs, together with pressure to decarbonize generation and the appearance of new disruptive technologies suggest there will be a change in the structure of this sector. Some experts assure that the future of the power system will be distributed, while others argue that it will be centralized. As was suggested by the Florence School or Regulation, probably, the most accurate estimation is that it will be a mixture of both: a power grid oriented towards the smart grid paradigm, through the integration of RES, DDG, Storage and DR. This will alter to a great extent the current consumption-production pattern introducing a number of operational challenges, namely: predictability and a good coordination of these participants so as to guarantee the balance in the power system, security of supply and efficiency. This presents a very good opportunity for UC3M to carry out further research and evaluate the potential of the implementation of a microgrid project on campus.

Microgrids seem to be the best mechanism to integrate all energy participants, as well as having interesting characteristics such as the ability to switch between islanded and grid-tied operation, increasing reliability. The concept of microgrid presents itself as a good opportunity for investment, attracting market participation and improving network performance with issues such as congestion relief, voltage control and loss reduction, provided the appropriate conditions, such as efficient regulations and energy policies, exist.

Microgrids are electricity networks that count with distributed energy resources and are usually connected to the centralized grid while having a certain degree of autonomy; therefore, being able to operate partially or completely independently from it. They are especially useful in facilities where power reliability is of extreme importance or when network and market constraints are present, such as dynamic loads and intermittent generation, higher and more volatile electricity and gas prices or increasing the need for network automation and control.

Microgrids are great enablers of the transition to a more decentralised energy system, with bidirectional energy flows and conformed by different technologies, which will result in a more resilient grid. Furthermore, it favours the penetration of renewable resources, thus reducing pollutant emissions. It increases the efficiency of the electricity network, reducing peak demand and therefore the requirements of installed capacity.

9.2. Solar Microgrid

According to PVSol Software, 4.8 kWh of battery per kWp of installed PV are recommended for the proper operation of the system. This comprises the accommodation of solar generation that exceeds consumption, which can be employed when solar production is not available and consumed locally, having less transmission losses. However, this would be valid without taking into account the minimum load or if the minimum load was zero. Instead, in the case under analysis, the parameter that has been considered for the battery sizing is the mean of the nonzero elements of the surplus of PV generation. This amount of power has been obtained, amounting to 160.6379 kW, which will be the required size of the inverter. Moreover, this parameter has also been used for the battery sizing, by multiplying it by the above mentioned 4.8, resulting in a size of 771.0621 kWh $\sim$ 770 kWh.

The introduction of a storage system has related benefits such as the potential for demand response and peak shaving as well as increasing efficiency and reliability of the system. However, given that in the case under analysis the electricity network presents a very high reliability and it is possible to sell the surplus of solar generation to the grid, it results more economically viable not to install batteries.

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ANNEX A:PRODUCT DATASHEETS

PV Module: SPR-X22-360		
Manufacturer	SunPower	
Available	Yes	
Electrical Data		
Cell Type	Si monocrystalline	
Only Transformer Inverters suitable	No	
Number of Cells	96	
Number of Bypass Diodes	3	
Mechanical Data		
Width	1046	mm
Height	1559	mm
Depth	46	mm
Frame Width	7	mm
Weight	18.6	kg
Framed	No	
I/V Characteristics at STC		
MPP Voltage	60.6	V
MPP Current	5.94	A
Nominal output	360	W
Open Circuit Voltage	69.5	V
Short-Circuit Current	6.48	A
Increase open circuit voltage before stabilisation	0	%
I/V Part Load Characteristics		
Values source	Manufacturer/user-created	
Irradiance	200	W/m²
Voltage in MPP at Part Load	57.95	V
Current in MPP at Part Load	1.2	A
Open Circuit Voltage (Part Load)	65.53	V
Short Circuit Current at Part Load	1.3	A
Further		
Voltage Coefficient	-167.4	mV/K
Electricity Coefficient	3.5	mA/K
Output Coefficient	-0.3	%/K
Incident Angle Modifier	100	%
Maximum System Voltage	1000	V
Spec. Heat Capacity	920	J/(kg*K)
Absorption Coefficient	70	%
Emissions Coefficient	85	%

Inverter: FRONIUS CL 48,0

Manufacturer	Fronius International	
Available	Yes	

Electrical Data		
DC Power Rating	50.63	kW
AC Power Rating	48	kW
Max. DC Power	51.4	kW
Max. AC Power	48	kVA
Standby Consumption	94.2	W
Night Consumption	11.6	W
Feed-in from	95	W
Max. Input Current	335.2	A
Max. Input Voltage	600	V
Nom. DC Voltage	370	V
Number of Feed-in Phases	3	
Number of DC Inlets	3	
With Transformer	Yes	
Change in Efficiency when Input Voltage deviates from Rated Voltage	-0.47	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	99.9	%
Output Range > 20% of Power Rating	99.9	%
No. of MPP Trackers	1	
Max. Input Current per MPP Tracker	335.2	A
Max. Input Power per MPP Tracker	51.4	kW
Min. MPP Voltage	230	V
Max. MPP Voltage	500	V

Inverter: TRIO-TM-50.0

Manufacturer	ABB	
Available	Yes	

Electrical Data		
DC Power Rating	51.2	kW
AC Power Rating	50	kW
Max. DC Power	70	kW
Max. AC Power	50	kVA
Standby Consumption	1	W
Night Consumption	1	W
Feed-in from	100	W
Max. Input Current	110	A
Max. Input Voltage	1000	V
Nom. DC Voltage	610	V
Number of Feed-in Phases	3	
Number of DC Inlets	1	
With Transformer	No	
Change in Efficiency when Input Voltage deviates from Rated Voltage	0.34	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	99.5	%
Output Range > 20% of Power Rating	99.8	%
No. of MPP Trackers	3	
MPP Tracker 1		
Max. Input Current per MPP Tracker	55	A
Max. Input Power per MPP Tracker	17.5	kW
Min. MPP Voltage	480	V
Max. MPP Voltage	800	V
MPP Tracker 2		
Max. Input Current per MPP Tracker	55	A
Max. Input Power per MPP Tracker	17.5	kW
Min. MPP Voltage	480	V
Max. MPP Voltage	800	V

Inverter: Sunny Tripower CORE1

Manufacturer	SMA Solar Technology AG	
Available	Yes	

Electrical Data		
DC Power Rating	51	kW
AC Power Rating	50	kW
Max. DC Power	51	kW
Max. AC Power	50	kVA
Standby Consumption	4.8	W
Night Consumption	4.8	W
Feed-in from	120	W
Max. Input Current	120	A
Max. Input Voltage	1000	V
Nom. DC Voltage	670	V
Number of Feed-in Phases	3	
Number of DC Inlets	12	
With Transformer	No	
Change in Efficiency when Input Voltage deviates from Rated Voltage	-0.49	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	99.9	%
Output Range > 20% of Power Rating	100	%
No. of MPP Trackers	6	
Max. Input Current per MPP Tracker	20	A
Max. Input Power per MPP Tracker	16	kW
Min. MPP Voltage	150	V
Max. MPP Voltage	800	V

Inverter: Sunny Tripower 15000TL-30

Manufacturer	SMA Solar Technology AG	
Available	Yes	

Electrical Data		
DC Power Rating	15.33	kW
AC Power Rating	15	kW
Max. DC Power	15.33	kW
Max. AC Power	15	kVA
Standby Consumption	84	W
Night Consumption	1	W
Feed-in from	84	W
Max. Input Current	66	A
Max. Input Voltage	1000	V
Nom. DC Voltage	600	V
Number of Feed-in Phases	3	
Number of DC Inlets	6	
With Transformer	No	
Change in Efficiency when Input Voltage deviates from Rated Voltage	-0.49	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	97	%
Output Range > 20% of Power Rating	100	%
No. of MPP Trackers	2	
Max. Input Current per MPP Tracker	33	A
Max. Input Power per MPP Tracker	15	kW
Min. MPP Voltage	240	V
Max. MPP Voltage	800	V

Inverter: PVI-12.5-TL-OUTD

Manufacturer	ABB	
Available	Yes	

Electrical Data		
DC Power Rating	12.8	kW
AC Power Rating	12.5	kW
Max. DC Power	14.2	kW
Max. AC Power	13.8	kVA
Standby Consumption	10	W
Night Consumption	2	W
Feed-in from	30	W
Max. Input Current	36	A
Max. Input Voltage	900	V
Nom. DC Voltage	580	V
Number of Feed-in Phases	3	
Number of DC Inlets	6	
With Transformer	No	
Change in Efficiency when Input Voltage deviates from Rated Voltage	0.4	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	99.5	%
Output Range > 20% of Power Rating	99.8	%
No. of MPP Trackers	2	
Max. Input Current per MPP Tracker	18	A
Max. Input Power per MPP Tracker	8	kW
Min. MPP Voltage	200	V
Max. MPP Voltage	850	V

Inverter: FRONIUS IG Plus 100 V-3

Manufacturer	Fronius International	
Available	Yes	

Electrical Data		
DC Power Rating	8.39	kW
AC Power Rating	8	kW
Max. DC Power	8.43	kW
Max. AC Power	8	kVA
Standby Consumption	17.5	W
Night Consumption	1.72	W
Feed-in from	45	W
Max. Input Current	55.1	A
Max. Input Voltage	600	V
Nom. DC Voltage	370	V
Number of Feed-in Phases	3	
Number of DC Inlets	6	
With Transformer	Yes	
Change in Efficiency when Input Voltage deviates from Rated Voltage	-0.35	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	99.96	%
Output Range > 20% of Power Rating	99.99	%
No. of MPP Trackers	1	
Max. Input Current per MPP Tracker	55.1	A
Max. Input Power per MPP Tracker	8.43	kW
Min. MPP Voltage	230	V
Max. MPP Voltage	500	V

Inverter: FRONIUS CL 48,0

Manufacturer	Fronius International	
Available	Yes	

Electrical Data		
DC Power Rating	50.63	kW
AC Power Rating	48	kW
Max. DC Power	51.4	kW
Max. AC Power	48	kVA
Standby Consumption	94.2	W
Night Consumption	11.6	W
Feed-in from	95	W
Max. Input Current	335.2	A
Max. Input Voltage	600	V
Nom. DC Voltage	370	V
Number of Feed-in Phases	3	
Number of DC Inlets	3	
With Transformer	Yes	
Change in Efficiency when Input Voltage deviates from Rated Voltage	-0.47	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	99.9	%
Output Range > 20% of Power Rating	99.9	%
No. of MPP Trackers	1	
Max. Input Current per MPP Tracker	335.2	A
Max. Input Power per MPP Tracker	51.4	kW
Min. MPP Voltage	230	V
Max. MPP Voltage	500	V

Inverter: PVI-12.5-TL-OUTD

Manufacturer	ABB	
Available	Yes	

Electrical Data		
DC Power Rating	12.8	kW
AC Power Rating	12.5	kW
Max. DC Power	14.2	kW
Max. AC Power	13.8	kVA
Standby Consumption	10	W
Night Consumption	2	W
Feed-in from	30	W
Max. Input Current	36	A
Max. Input Voltage	900	V
Nom. DC Voltage	580	V
Number of Feed-in Phases	3	
Number of DC Inlets	6	
With Transformer	No	
Change in Efficiency when Input Voltage deviates from Rated Voltage	0.4	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	99.5	%
Output Range > 20% of Power Rating	99.8	%
No. of MPP Trackers	2	
Max. Input Current per MPP Tracker	18	A
Max. Input Power per MPP Tracker	8	kW
Min. MPP Voltage	200	V
Max. MPP Voltage	850	V

Inverter: Sunny Tripower CORE1

Manufacturer	SMA Solar Technology AG
Available	Yes

Electrical Data		
DC Power Rating	51	kW
AC Power Rating	50	kW
Max. DC Power	51	kW
Max. AC Power	50	kVA
Standby Consumption	4.8	W
Night Consumption	4.8	W
Feed-in from	120	W
Max. Input Current	120	A
Max. Input Voltage	1000	V
Nom. DC Voltage	670	V
Number of Feed-in Phases	3	
Number of DC Inlets	12	
With Transformer	No	
Change in Efficiency when Input Voltage deviates from Rated Voltage	-0.49	%/100V

MPP Tracker		
Output Range < 20% of Power Rating	99.9	%
Output Range > 20% of Power Rating	100	%
No. of MPP Trackers	6	
Max. Input Current per MPP Tracker	20	A
Max. Input Power per MPP Tracker	16	kW
Min. MPP Voltage	150	V
Max. MPP Voltage	800	V

ANNEX B: MATLAB SCRIPT

```matlab
clear all;
clc;

%% Variables to be obtained through PVSol

%Installed PV Capacity in Leganes part 1
CPV1=518.76; %[kWp]
%Installed PV Capacity in Leganes part 2
CPV2=421.2; %[kWp]
%Installed PV Capacity
CPV=CPV1+CPV2; %[kWp]

% This includes the cost of PV modules, inverters and structural and
% electrical components.

%Capital Costs (to be obtained through PVSol)
%Capital Costs Leganes part 1
PV_CAPEX1=778140; %[EUR]
%Capital Costs Leganes part 2
PV_CAPEX2=631800; %[EUR]
PV_CAPEX= PV_CAPEX1+PV_CAPEX2; %[EUR]
%

%% Operation and Maintenance Costs

PV_OM(1)=20.28*CPV;
%[EPRI] -> 20-22 USD/kWp/year

for i=2:20
PV_OM(i)=PV_OM(i-1)*1.02;
end

% Reference: [The annual O&M costs account for 1% of the ...
    installation cost. Source: [Talavera et al., 2010, 2016] at ...
    an annual 2% escalation rate according to the long term ECB ...
    inflation target]

%% Electricity Retail Prices

% Creating time vector
t1 = datetime(2016,1,1,1,0,0);
t2 = datetime(2016,12,30,24,0,0);
t = (t1:hours(1):t2) ;
months = t.Month;
hours = t.Hour;
```

```
day = day(t);

%%Tarifa 6.1A for high voltage
% ==============================================================

%Price of Energy

% OMIE Part - Mercado Ib rico de Electricidad, rama Espa ola
OMIE = [0.053466 0.04904 0.048627 0.046418 0.044693 0.038879];
Ms = [1.065552 1.066984 1.072129 1.069251 1.074975 1.093287];
As = [0.045088 0.035301 0.023815 0.018163 0.015622 0.012234];

% OMIP Part - Mercado Ib rico de Electricidad, rama Portuguesa
OMIP = [0.045 0.045 0.045 0.045 0.045 0.045];
Mf = [1.086863 1.088324 1.093572 1.090636 1.096475 1.115153];
Af = [0.045838 0.036051 0.024565 0.018913 0.016372 0.012984];

%Precio de la Energ a = % cerrado en OMIP x (OMIP x Mf + Af) + ...
    % abierto a OMIE x (OMIE x Ms + As)
% Precio de la Energia
P1 = 0.5*(OMIE.*Ms+As)+0.5*(OMIP.*Mf+Af);
% P1 = [0.026674 0.019921 0.010615 0.005283 0.003411 0.002137];
%
% %Peajes de acceso
P2=[0.013630 0.006291 0.004193 0.003145 0.003145 0];
P = P1+P2;

%Creating price vector- selects the price per kWh dependent on ...
    the hour of day and month
price_vector = zeros(8760,1);
for i = 1 : 8760
% P6
if hours(i) ≤ 7 || months(i) == 8
price_vector(i) = P(6);

% P5
elseif hours(i) ≥ 8 && ismember(months(i),[4 5 10])
price_vector(i) = P(5);
% P4
elseif ismember(hours(i),[8:15 22 23]) && ismember(months(i),[3 11])
price_vector(i) = P(4);
elseif ismember(hours(i),[8 15:23]) && months(i) == 9
price_vector(i) = P(4);
elseif ismember(hours(i),[8 15:23]) && months(i) == 6 && day(i) ≤...
     15
price_vector(i) = P(4);
% P3
elseif ismember(hours(i),16:21) && ismember(months(i),[3 11])
price_vector(i) = P(3);
elseif ismember(hours(i),9:14) && months(i) == 9
price_vector(i) = P(3);
```

```
elseif ismember(hours(i),9:14) && months(i) == 6 && day(i) ≤ 15
price_vector(i) = P(3);
% P2
elseif ismember(hours(i),[8 9 13:17 21:23]) && ...
    ismember(months(i),[1 2 12])
price_vector(i) = P(2);
elseif ismember(hours(i),[8:10 19:23]) && months(i) == 7
price_vector(i) = P(2);
elseif ismember(hours(i),[8:10 19:23]) && months(i) == 6 && ...
    day(i) > 15
price_vector(i) = P(2);
% P1
elseif ismember(hours(i),[10:12 18:20]) && ismember(months(i),[1 ...
    2 12])
price_vector(i) = P(1);
elseif ismember(hours(i),11:18) && months(i) == 7
price_vector(i) = P(1);
else
price_vector(i) = P(1);
end
end

%Plot results
figure;
plot(t, price_vector);
ylabel( EUR/ kWh );
title( ToU Tariff );
%

%% GHI

Solar_radiation = readtable( GHI.xlsx );

%Solar radiation onto the horizontal plane  [kWh/m^2]
Solar_irradiance_horizontal_plane = ...
    Solar_radiation.Irradiance_onto_horizontal_plane_kWh_m_2;

%Diffuse Irradiation onto Horizontal Plane [kWh/m^2]
Diffuse_irradiation_horizontal_plane = ...
Solar_radiation.Diffuse_Irradiation_onto_Horizontal_Plane_kWh_m_2;

%Plot results
figure;
plot(t,Solar_irradiance_horizontal_plane, LineWidth , 1);
hold on;
plot(t,Diffuse_irradiation_horizontal_plane, LineWidth , 1);
hold off;
title( Global Horizontal Irradiation );
ylabel( [kWh/ m  ] );
legend( Solar radiation onto the horizontal plane , Diffuse ...
    Irradiation onto Horizontal Plane );
```

```
%

%% PV Generation

pvgen=readtable( Total PV Output Power.xlsx );
pv_Generation = pvgen.TotalPVOutputPower;

figure;
plot(t, pv_Generation, y );
title( PV Generation );
ylabel( kW );

Deg_Rate = 0.008;
% [Source: Sale of profitable but unaffordable PV plants in ...
    Spain: Analysis of a real case]

PV_Generation(:,1) = pv_Generation;

for i=2:20
PV_Generation(:,i) = PV_Generation(:,i-1)*(1-Deg_Rate);
end
%

%Percentage of losses = 5.83% [Source: PVSol]
Perc_losses = 0.0583;
PV_Generation = PV_Generation*(1-Perc_losses);
%

%% Load
%
Load = readtable( Load.xlsx );
Leganes_Load = Load.Potencia_kW;

Hourly_load = sum(reshape(Leganes_Load,4,8760)) ; % as the data ...
    for the load was given in quarterly values, it must be ...
    converted to hourly values
Hourly_load=Hourly_load/4;

%Plot results
figure;
plot(t,Hourly_load);
title( Legan s Load );
ylabel( kW );

% annual increase in load, load escalation rate increase in 0.8%
%Source: [BOE Orden ETU/315/2017]
L_ER = 0.008;

hourly_load(:,1) = Hourly_load;

for i=2:20
```

```
hourly_load(:,i) = hourly_load(:,i-1)*(1+L_ER);
end
%

%% Grid Consumption

Grid_Purchases_kW = hourly_load - PV_Generation;

PV_Sold = zeros (8760,1);

for i=1:8760

if Grid_Purchases_kW(i) < 0
PV_Sold(i) = - Grid_Purchases_kW(i);
Grid_Purchases_kW(i) = 0;
end

end

%Plot results
figure;
plot(t,Hourly_load, LineWidth , 1);
hold on;
plot(t,Grid_Purchases_kW(:,1), LineWidth , 1);
plot(t, pv_Generation, LineWidth , 1);
plot(t, PV_Sold(:,1), LineWidth , 1);
hold off;
legend( Hourly Load , Grid Purchases , PV Generation , PV Sold ...
    to the Grid );
ylabel( kWh );
title( System Operation and Power Flows );

%% PV Generation to Cover the Load

PV_Load = PV_Generation - PV_Sold;

%Percentage of PV production to cover the load
Percent_PV_Load = mean(sum(PV_Load)/sum(PV_Generation))*100;
%
%% Renewable Fraction

Annual_Renewable_frac = (sum(PV_Load)/sum(hourly_load))*100;
Renewable_frac = mean(Annual_Renewable_frac);
%
%% Costs for Contracted Capacity

%%Termino de potencia price and contracted capacity
P_BOE = [0.107231 0.053662 0.039272 0.039272 0.039272 0.017918];
%source BOE
capacity_BOE = [1900 1900 1900 1900 1900 3035];

```

```
%Source
%Expected Annual Escalation Rate of 2% in Electricity Prices
%Source [Talavera et al. (2010) & EPIA (2011)]

% Contracted Capacity Annual Costs-Fixed Annual Electricity Costs
Annual_P_BOE = 365*sum(P_BOE.*capacity_BOE);
% Source BOE

for i=2:20
Annual_P_BOE(i)=Annual_P_BOE(i-1)*1.02;
end


%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%% Compensation Schemes
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

%% Wholesale Electricity Prices

SBP=OMIE;
sellback_price_vector = zeros(8760,1);
for i = 1 : 8760
% P6
if hours(i) ≤ 7 || months(i) == 8
sellback_price_vector(i) = SBP(6);

% P5
elseif hours(i) ≥ 8 && ismember(months(i),[4 5 10])
sellback_price_vector(i) = SBP(5);
% P4
elseif ismember(hours(i),[8:15 22 23]) && ismember(months(i),[3 11])
sellback_price_vector(i) = SBP(4);
elseif ismember(hours(i),[8 15:23]) && months(i) == 9
sellback_price_vector(i) = SBP(4);
elseif ismember(hours(i),[8 15:23]) && months(i) == 6 && day(i) ≤...
    15
sellback_price_vector(i) = SBP(4);
% P3
elseif ismember(hours(i),16:21) && ismember(months(i),[3 11])
sellback_price_vector(i) = SBP(3);
elseif ismember(hours(i),9:14) && months(i) == 9
sellback_price_vector(i) = SBP(3);
elseif ismember(hours(i),9:14) && months(i) == 6 && day(i) ≤ 15
sellback_price_vector(i) = SBP(3);
% P2
elseif ismember(hours(i),[8 9 13:17 21:23]) && ...
   ismember(months(i),[1 2 12])
sellback_price_vector(i) = SBP(2);
elseif ismember(hours(i),[8:10 19:23]) && months(i) == 7
sellback_price_vector(i) = SBP(2);
```

```
elseif ismember(hours(i),[8:10 19:23]) && months(i) == 6 && ...
    day(i) > 15
sellback_price_vector(i) = SBP(2);
% P1
elseif ismember(hours(i),[10:12 18:20]) && ismember(months(i),[1 ...
    2 12])
sellback_price_vector(i) = SBP(1);
elseif ismember(hours(i),11:18) && months(i) == 7
sellback_price_vector(i) = SBP(1);
else
sellback_price_vector(i) = SBP(1);
end
end

%Plot results
figure;
plot(t,sellback_price_vector);
title( Wholesale Price );
ylabel( EUR/kWh );


for i=2:20

sellback_price_vector(:,i)=sellback_price_vector(:,i-1)*1.02;
price_vector(:,i)=price_vector(:,i-1)*1.02;

end
%

%Including 21% VAT
Annual_P_BOE = Annual_P_BOE*1.21;
price_vector = price_vector*1.21;
%
%% Feed in tariffs

% Source (RD) 14/2010
% 0.15675 EUR/kWh

FiT(1)=0.15675;

% Assumed Escalation Rate of 2% to match the electricity price ...
    escalation rate. Source: [Sale of profitable but ...
    unaffordable PV plants in Spain]

FiT_ER=0.02;
for i=2:20

FiT(i)=FiT(i-1)*(1+FiT_ER);

end
%
```

```

%% Charges

%%Backup Charges

%Variable Backup Charge
% VBC: variable back-up charge (variable tax to ...
    self-consumption) [0.0194 EUR/self-consumed kWh] *
VBC=0.0194; %[EUR/kWh]
%Source:RD 900/2015

% Generation_Tax
% 7% of Revenues from Sold Electricity
Generation_Tax=0.07;
%Source:[Law 15/2012]

%Grid Access Charge
% Access charge (0.5 EUR/ exported MWh)
Access_Charge=0.0005; %[EUR/MWh]
%Source:[RD 1544/2011]

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%% Base Costs

Base_Costs = price_vector.*hourly_load;
Annual_Base_Costs = sum(Base_Costs)+Annual_P_BOE;
%
%% Annual Costs

%Years- Vector of the years considered under the analysis
y=1:20;

%% Financing Costs

%Percentage of external financing
PEF=0.6;

%Part of the investment covered through external financing - Loan
Loan = PEF*PV_CAPEX;

%Part of the investment covered through private equity
Priv_Eq(1) = (1-PEF)*PV_CAPEX;
Priv_Eq(2:20) = 0;

Int_rate = [1.58 1.63 1.62 1.64 1.59 1.62 1.66 1.68 1.61 1.63 ...
    1.60 1.65 1.63]/100;
Interest_Rate = mean(Int_rate);
%Source: [ECB (European Central Bank) Interest rates for loans ...
    within the euro area for non-finantial corporations with a ...
    maturity of 10 years and with a value between 0.25 Meuros ...
    and 1 Meuros. Average rates from February 2017 to February 2018]
```

```
Interests(1:10) = Interest_Rate * Loan;
Interests(11:20) = 0;

Loan_Repayment(1:20) = 0;
Loan_Repayment(10) = Loan;
%

%% Scenario 0_1: Hourly Values WP, Generation Tax, Grid Access ...
    Charge, Backup Charges

% Annual Costs
Annual_Cost0_1=Priv_Eq+Loan_Repayment+Interests+PV_OM+...
sum(Grid_Purchases_kW.*price_vector)+sum(VBC.*PV_Load)+...
Annual_P_BOE-sum((1-Generation_Tax)*(sellback_price_vector-...
Access_Charge).*PV_Sold);
%

% Total Annual Savings
Annual_Savings0_1=Annual_Base_Costs-Annual_Cost0_1;

%Simple Payback
Cumulative_Sum_Annual_Savings0_1=cumsum(Annual_Savings0_1);

f = @(x)interp1(y,Cumulative_Sum_Annual_Savings0_1,x, linear ,...
 extrap ) ;
Payback0_1=fzero(f,15);
%

% Annual Savings from Sale of electriciy into the grid (revenues)
Annual_Rev_PV_0_1 = sum((1-Generation_Tax)*...
(sellback_price_vector-Access_Charge).*PV_Sold);

% Annual Savings from Self Consumption
Annual_Sav_SC_0_1 = Annual_Savings0_1-Annual_Rev_PV_0_1;

%vector of savings for plot
Savings_Type_0_1 = [Annual_Rev_PV_0_1  Annual_Sav_SC_0_1 ];

%Plot Savings
figure;
subplot(2,2,1);
bar(Annual_Rev_PV_0_1);
title( Annual Savings from Sale of electriciy into the grid ...
    (revenues) );

subplot(2,2,2);
bar(Annual_Sav_SC_0_1, y );
title( Annual Savings from Self Consumption );

subplot(2,2,[3,4]);
bar(Savings_Type_0_1, stacked );
```

```
title( Annual Savings under Scenario 1 );
legend( Annual Revenues from Sale of Electricity , Annual ...
    Savings from Self-Consumption , Location , SouthEast );
xlabel( Years );
ylabel( EUR );

%Percentage revenues from grid exports of total savings - ...
    scenario 1
Percent_Rev_01 = ...
    (sum(Annual_Rev_PV_0_1)/sum(Annual_Savings0_1))*100;
%

%% Scenario 0_2:WP, Generation Tax, Grid Access Charges, backup ...
    charges for self consumption, Tender Compensation.

%Retribuci n a la inversi n
%RI [EUR/installed kWp]
%Source:[Orden ETU/315/2017]

RI(1)=39.646;
for i=2:20
RI(i)=0;
end

% Annual Costs
Annual_Cost0_2=Priv_Eq+Loan_Repayment+Interests+PV_OM+...
sum(Grid_Purchases_kW.*price_vector)+sum(VBC.*PV_Load)+...
Annual_P_BOE-sum((1-Generation_Tax)*(sellback_price_vector-...
Access_Charge).*PV_Sold)-RI.*CPV;

%Annual Savings
Annual_Savings0_2=Annual_Base_Costs-Annual_Cost0_2;

%Simple Payback
Cumulative_Sum_Annual_Savings0_2=cumsum(Annual_Savings0_2);

f = @(x)interp1(y,Cumulative_Sum_Annual_Savings0_2,x, linear ,...
 extrap ) ;
Payback0_2 = fzero(f,15);
%

% Annual Savings from Sale of electriciy into the grid (revenues)
Annual_Rev_PV_0_2 = sum((1-Generation_Tax)*...
(sellback_price_vector-Access_Charge).*PV_Sold);

% Annual Savings from Self Consumption
Annual_Sav_SC_0_2 = Annual_Savings0_2-Annual_Rev_PV_0_2;

%vector of savings for plot
Savings_Type_0_2 = [Annual_Rev_PV_0_2  Annual_Sav_SC_0_2 ];

```

```
%Plot Savings
figure;
subplot(2,2,1);
bar(Annual_Rev_PV_0_2);
title( Annual Savings from Sale of electriciy into the grid ...
    (revenues) );

subplot(2,2,2);
bar(Annual_Sav_SC_0_2, y );
title( Annual Savings from Self Consumption );

subplot(2,2,[3,4]);
bar(Savings_Type_0_2, stacked );
title( Annual Savings under Scenario 2 );
legend( Annual Revenues from Sale of Electricity , Annual ...
    Savings from Self-Consumption , Location , SouthEast );
xlabel( Years );
ylabel( EUR );
%

%Percentage revenues from grid exports of total savings - ...
    scenario 2
Percent_Rev_02 = ...
    (sum(Annual_Rev_PV_0_2)/sum(Annual_Savings0_2))*100;
%

% Relative increase in savings with respect to base scenario
Rel_Rev_02 = mean((Annual_Rev_PV_0_2-...
Annual_Rev_PV_0_1)./Annual_Rev_PV_0_1)*100;
Rel_Sav_SC_02 = mean((Annual_Sav_SC_0_2-...
Annual_Sav_SC_0_1)./Annual_Sav_SC_0_1)*100;
%

%% Scenario 0_3: WP no backup charges, no generation tax nor ...
    grid access charge - 80% externally financed

% Annual Costs
Annual_Cost0_3=Priv_Eq+Loan_Repayment+Interests+PV_OM+...
sum(Grid_Purchases_kW.*price_vector)+Annual_P_BOE-...
sum(sellback_price_vector.*PV_Sold);
%

%Annual Savings
Annual_Savings0_3=Annual_Base_Costs-Annual_Cost0_3;

%Simple Payback
Cumulative_Sum_Annual_Savings0_3=cumsum(Annual_Savings0_3);

f = @(x)interp1(y,Cumulative_Sum_Annual_Savings0_3,x,...
 linear , extrap ) ;
Payback0_3=fzero(f,15);
```

```
%

% Annual Savings from Sale of electriciy into the grid (revenues)
Annual_Rev_PV_0_3 = sum(sellback_price_vector.*PV_Sold);

% Annual Savings from Self Consumption
Annual_Sav_SC_0_3 = Annual_Savings0_3-Annual_Rev_PV_0_3;

%vector of savings for plot
Savings_Type_0_3 = [Annual_Rev_PV_0_3  Annual_Sav_SC_0_3 ];

%Plot Savings
figure;
subplot(2,2,1);
bar(Annual_Rev_PV_0_3);
title( Annual Savings from Sale of electriciy into the grid ...
    (revenues) );

subplot(2,2,2);
bar(Annual_Sav_SC_0_3, y );
title( Annual Savings from Self Consumption );

subplot(2,2,[3,4]);
bar(Savings_Type_0_3, stacked );
title( Annual Savings under Scenario 3 );
legend( Annual Revenues from Sale of Electricity , Annual ...
    Savings from Self-Consumption , Location , SouthEast );
xlabel( Years );
ylabel( EUR );
%

%Percentage revenues from grid exports of total savings - ...
    scenario 3
Percent_Rev_03 = ...
    (sum(Annual_Rev_PV_0_3)/sum(Annual_Savings0_3))*100;
%

% Relative increase in savings with respect to base scenario
Rel_Rev_03 = mean((Annual_Rev_PV_0_3-...
Annual_Rev_PV_0_1)./Annual_Rev_PV_0_1)*100;
Rel_Sav_SC_03 = mean((Annual_Sav_SC_0_3-...
Annual_Sav_SC_0_1)./Annual_Sav_SC_0_1)*100;
%

%% Scenario 0_4: Feed-in-tariff no backup charges

% Annual Costs
Annual_Cost0_4=Priv_Eq+Loan_Repayment+Interests+PV_OM+...
sum(Grid_Purchases_kW.*price_vector)+Annual_P_BOE-sum(FiT.*PV_Sold);

%Annual Savings
```

```
Annual_Savings0_4=Annual_Base_Costs-Annual_Cost0_4;

%Simple Payback
Cumulative_Sum_Annual_Savings0_4=cumsum(Annual_Savings0_4);

f = @(x)interp1(y,Cumulative_Sum_Annual_Savings0_4,x, linear ,...
 extrap ) ;
Payback0_4 = fzero(f,15);
%

% Annual Savings from Sale of electriciy into the grid (revenues)
Annual_Rev_PV_0_4 = sum(FiT.*PV_Sold);

% Annual Savings from Self Consumption
Annual_Sav_SC_0_4 = Annual_Savings0_4-Annual_Rev_PV_0_4;

%vector of savings for plot
Savings_Type_0_4 = [Annual_Rev_PV_0_4  Annual_Sav_SC_0_4 ];

%Plot Savings
figure;
subplot(2,2,1);
bar(Annual_Rev_PV_0_4);
title( Annual Savings from Sale of electriciy into the grid ...
    (revenues) );

subplot(2,2,2);
bar(Annual_Sav_SC_0_4, y );
title( Annual Savings from Self Consumption );

subplot(2,2,[3,4]);
bar(Savings_Type_0_4, stacked );
title( Annual Savings under Scenario 4 );
legend( Annual Revenues from Sale of Electricity , Annual ...
    Savings from Self-Consumption , Location , SouthEast );
xlabel( Years );
ylabel( EUR );
%

%Percentage revenues from grid exports of total savings - ...
    scenario 4
Percent_Rev_04 = ...
    (sum(Annual_Rev_PV_0_4)/sum(Annual_Savings0_4))*100;
%

% Relative increase in savings with respect to base scenario
Rel_Rev_04 = mean(((Annual_Rev_PV_0_4-...
Annual_Rev_PV_0_1)./Annual_Rev_PV_0_1))*100;
%

%% Scenario 0_5: Net Metering no backup charges
```

```
% Annual Costs
Annual_Cost0_5=Priv_Eq+Loan_Repayment+Interests+PV_OM+...
sum(Grid_Purchases_kW.*price_vector)+Annual_P_BOE-...
sum(price_vector.*PV_Sold);
%

%Annual Savings
Annual_Savings0_5=Annual_Base_Costs-Annual_Cost0_5;

%Simple Payback
Cumulative_Sum_Annual_Savings0_5=cumsum(Annual_Savings0_5);

f = @(x)interp1(y,Cumulative_Sum_Annual_Savings0_5,x, linear ,...
 extrap ) ;
Payback0_5 = fzero(f,15);
%

% Annual Savings from Sale of electriciy into the grid (revenues)
Annual_Rev_PV_0_5 = sum(price_vector.*PV_Sold);

% Annual Savings from Self Consumption
Annual_Sav_SC_0_5 = Annual_Savings0_5-Annual_Rev_PV_0_5;

%vector of savings for plot
Savings_Type_0_5 = [Annual_Rev_PV_0_5  Annual_Sav_SC_0_5 ];

%Plot Savings
figure;
subplot(2,2,1);
bar(Annual_Rev_PV_0_5);
title( Annual Savings from Sale of electriciy into the grid ...
    (revenues) );

subplot(2,2,2);
bar(Annual_Sav_SC_0_5, y );
title( Annual Savings from Self Consumption );

subplot(2,2,[3,4]);
bar(Savings_Type_0_5, stacked );
title( Annual Savings under Scenario 5 );
legend( Annual Revenues from Sale of Electricity , Annual ...
    Savings from Self-Consumption , Location , SouthEast );
xlabel( Years );
ylabel( EUR );
%

%Percentage revenues from grid exports of total savings - ...
    scenario 5
Percent_Rev_05 = (sum(Annual_Rev_PV_0_5)/...
sum(Annual_Savings0_5))*100;
```

```
%

% Relative increase in savings with respect to base scenario
Rel_Rev_05 = mean((Annual_Rev_PV_0_5-...
Annual_Rev_PV_0_1)./Annual_Rev_PV_0_1))*100;

%Percentage revenues from grid exports of total savings - ...
    scenarios 1 to 5
Percent_Rel_Rev = (Percent_Rev_01+Percent_Rev_02+...
Percent_Rev_03+Percent_Rev_04+Percent_Rev_05)/5;
%

%% Comparison

%Plot savings
figure;

subplot(3,2,[1,2]),bar(Annual_Savings0_1);
title( Annual Savings under Scenario 1 );
xlabel( Years );
ylabel( EUR );

subplot(3,2,3),bar(Annual_Savings0_2);
title( Annual Savings under Scenario 2 );
xlabel( Years );
ylabel( EUR );

subplot(3,2,4),bar(y,Annual_Savings0_3);
xlabel( Years );
ylabel( EUR );
title( Annual Savings under Scenario 3 );

subplot(3,2,5),bar(y,Annual_Savings0_4);
xlabel( Years );
ylabel( EUR );
title( Annual Savings under Scenario 4 );

subplot(3,2,6),bar(y,Annual_Savings0_5);
xlabel( Years );
ylabel( EUR );
title( Annual Savings under Scenario 5 );
%

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

%Plot cumulative savings comparative among scenarios
figure;
plot(y,Cumulative_Sum_Annual_Savings0_1);
hold on;
plot(y,Cumulative_Sum_Annual_Savings0_2);
plot(y,Cumulative_Sum_Annual_Savings0_3);
```

```
plot(y,Cumulative_Sum_Annual_Savings0_4);
plot(y,Cumulative_Sum_Annual_Savings0_5);
hline = refline([0 0]);
hline.Color =  k ;
hold off;
title( Cumulative Savings )
legend( Scenario 1 , Scenario 2 , Scenario 3 , Scenario ...
    4 , Scenario 5 ,  , Location , NorthWest );
ylabel( EUR );
xlabel( years );
%

%% Payback Results

Payback_Results = [Payback0_1,Payback0_2,Payback0_3,Payback0_4,...
Payback0_5];
%
%% Discount Rate Determination

%Equity Investment. Investment financed through own capital
E = Priv_Eq(1);

%Debt --> Loan
D = Loan;

%Total Project Investment
V = E+D;

%Return on Equity --> Oportunity cost
Re = 0.07;
%Dividends from holding shares in Endesa [Source:Bolsa de Madrid ...
    (Madrid s Stock Exchange)]

%Return on Debt --> Loan interest rate
Rd = Interest_Rate;

%Weighted Average Cost of Capital
WACC = (E/V)*Re+(D/V)*Rd;

applicable_discount_rate = WACC;

%% NPV

r=0.03; %starting discount rate

for i=1:10


y=1:20;

discount_factor=1./((1+r).^y);
```

```
NPV_0_1(i)=sum(Annual_Savings0_1.*discount_factor);
NPV_0_2(i)=sum(Annual_Savings0_2.*discount_factor);
NPV_0_3(i)=sum(Annual_Savings0_3.*discount_factor);
NPV_0_4(i)=sum(Annual_Savings0_4.*discount_factor);
NPV_0_5(i)=sum(Annual_Savings0_5.*discount_factor);

%% LCOE

%LCOE of the base scenario
LCOE_0(i)=sum(Annual_Base_Costs.*discount_factor)/...
sum(sum(hourly_load).*discount_factor);

%LCOE of the system PV + grid - scenario 1
LCOE_0_1(i)=sum(Annual_Cost0_1.*discount_factor)/...
sum(sum(PV_Generation+Grid_Purchases_kW).*discount_factor);

%LCOE of the system PV + grid - scenario 2
LCOE_0_2(i)=sum(Annual_Cost0_2.*discount_factor)/...
sum(sum(PV_Generation+Grid_Purchases_kW).*discount_factor);

%LCOE of the system PV + grid - scenario 3
LCOE_0_3(i)=sum(Annual_Cost0_3.*discount_factor)/...
sum(sum(PV_Generation+Grid_Purchases_kW).*discount_factor);

%LCOE of the system PV + grid - scenario 4
LCOE_0_4(i)=sum(Annual_Cost0_4.*discount_factor)/...
sum(sum(PV_Generation+Grid_Purchases_kW).*discount_factor);

%LCOE of the system PV + grid - scenario 5
LCOE_0_5(i)=sum(Annual_Cost0_5.*discount_factor)/...
sum(sum(PV_Generation+Grid_Purchases_kW).*discount_factor);


r=r+0.01;

end

%% LCOE Comparison with Scenario 1
LCOE_Rel_2 = mean((LCOE_0_2-LCOE_0_1)./LCOE_0_1)*100;
LCOE_Rel_3 = mean((LCOE_0_3-LCOE_0_1)./LCOE_0_1)*100;
%
%%
discount_rate=[0.03 0.04 0.05 0.06 0.07 0.08 0.09 0.1 0.11 0.12];

results_LCOE = ...
    [LCOE_0_1;LCOE_0_2;LCOE_0_3;LCOE_0_4;LCOE_0_5;LCOE_0];

results_NPV = [NPV_0_1;NPV_0_2;NPV_0_3;NPV_0_4;NPV_0_5];
%
```

```
%% IRR determination

f = @(x)interp1(discount_rate,NPV_0_1,x, linear , extrap ) ;
IRR_0_1 = (fzero(f,15))*100;

f = @(x)interp1(discount_rate,NPV_0_2,x, linear , extrap ) ;
IRR_0_2 = (fzero(f,15))*100;

f = @(x)interp1(discount_rate,NPV_0_3,x, linear , extrap ) ;
IRR_0_3 = (fzero(f,15))*100;

f = @(x)interp1(discount_rate,NPV_0_4,x, linear , extrap ) ;
IRR_0_4 = (fzero(f,15))*100;

f = @(x)interp1(discount_rate,NPV_0_5,x, linear , extrap ) ;
IRR_0_5 = (fzero(f,15))*100;

%IRR Results
IRR_Results = [IRR_0_1,IRR_0_2,IRR_0_3,IRR_0_4,IRR_0_5];
%
%% Other Results - Plots

% LCOE System
figure;
plot(discount_rate,results_LCOE);
title( Discounted LCOE (PV + Grid) System vs Discount Rate );
xlabel( Discount Rate );
ylabel( LCOE [EUR / kWh] );
hold on;
plot([applicable_discount_rate applicable_discount_rate],[0.136 ...
    0.146], :r );
legend( LCOE under scenario 1 , LCOE under scenario 2 , LCOE ...
    under scenario 3 , LCOE under scenario 4 , LCOE under ...
    scenario 5 , LCOE under base scenario , Applicable Discount ...
    Rate , Location , Southwest );
hold off;

% NPV
figure;
plot(discount_rate,results_NPV);
title( NPV vs Discount Rate, All Scenarios );
xlabel( Discount Rate );
ylabel( NPV [EUR] );
hold on;
plot([applicable_discount_rate ...
    applicable_discount_rate],[-6*10^5 6*10^5], :r );
hline = refline([0 0]);
hline.Color =  k ;
legend( NPV under scenario 1 , NPV under scenario 2 , NPV under ...
    scenario 3 , NPV under scenario 4 , NPV under scenario ...
    5 , Applicable Discount Rate ,  );
```

```
%
%% NPV determination for current discount rate

NPV0_1 = ...
    interp1(discount_rate,NPV_0_1,applicable_discount_rate, linear );

NPV0_2 = ...
    interp1(discount_rate,NPV_0_2,applicable_discount_rate, linear );

NPV0_3 = ...
    interp1(discount_rate,NPV_0_3,applicable_discount_rate, linear );

NPV0_4 = ...
    interp1(discount_rate,NPV_0_4,applicable_discount_rate, linear );

NPV0_5 = ...
    interp1(discount_rate,NPV_0_5,applicable_discount_rate, linear );

Current_Results_NPV = [NPV0_1,NPV0_2,NPV0_3,NPV0_4,NPV0_5];
%
%% LCOE determination for current discount rate

%System LCOE
LCOE0_0 = ...
interp1(discount_rate,LCOE_0,applicable_discount_rate, linear );

LCOE0_1 = ...
interp1(discount_rate,LCOE_0_1,applicable_discount_rate, linear );

LCOE0_2 = ...
interp1(discount_rate,LCOE_0_2,applicable_discount_rate, linear );

LCOE0_3 = ...
interp1(discount_rate,LCOE_0_3,applicable_discount_rate, linear );

LCOE0_4 = ...
interp1(discount_rate,LCOE_0_4,applicable_discount_rate, linear );

LCOE0_5 = ...
interp1(discount_rate,LCOE_0_5,applicable_discount_rate, linear );

Current_Results_LCOE = ...
    [LCOE0_0,LCOE0_1,LCOE0_2,LCOE0_3,LCOE0_4,LCOE0_5];

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%% Further Research and Opportunities
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

%% Battery size

for i=1:8760
```

```
spill(i) = 0;
end
for i=1:8760
if PV_Sold(i) == 0
spill(i) = NaN;

else
spill(i) =  PV_Sold(i);
end
end

mean_Spill = nanmean(spill);

% Required battery size in kWh
battery_size = 4.8 * mean_Spill;
```